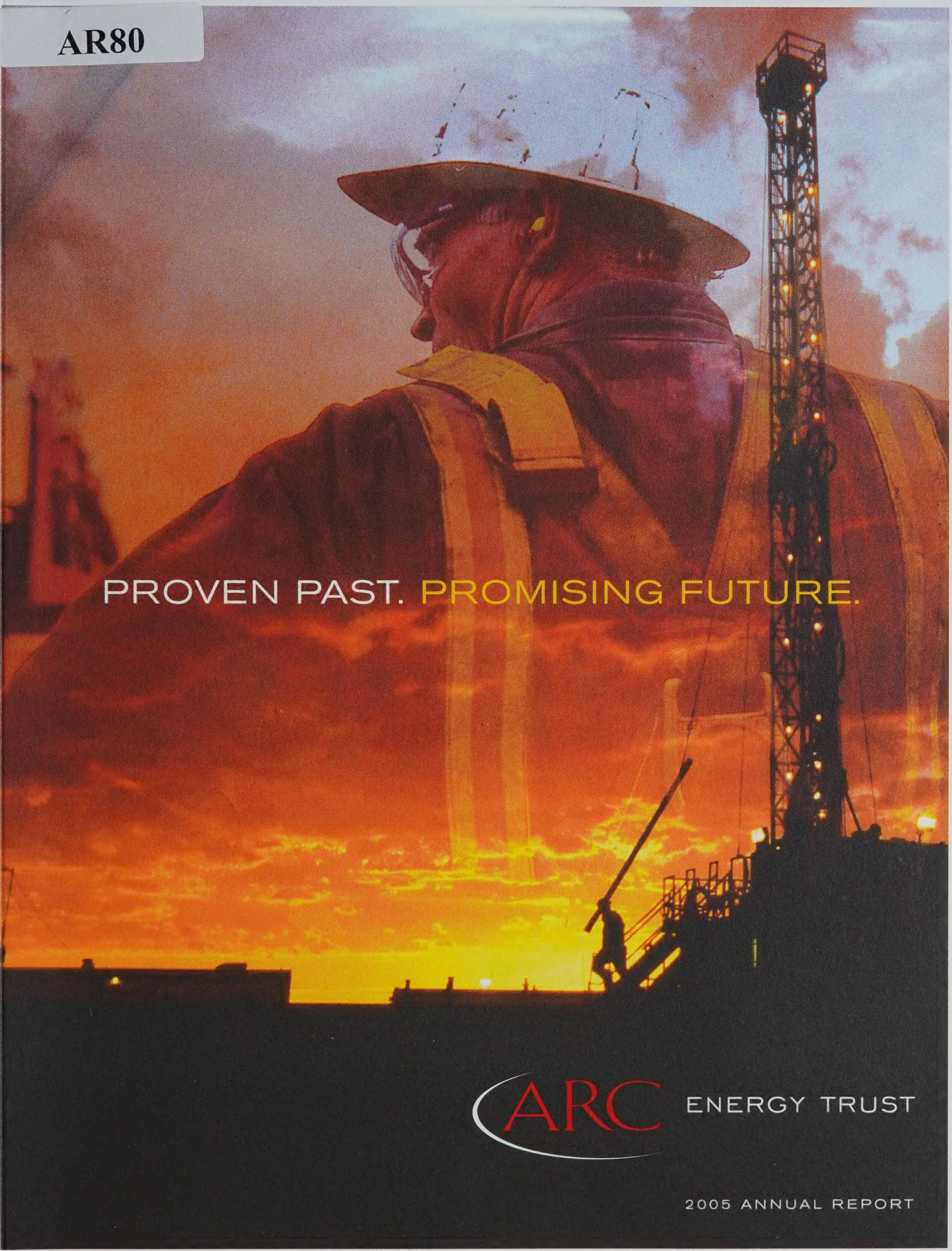
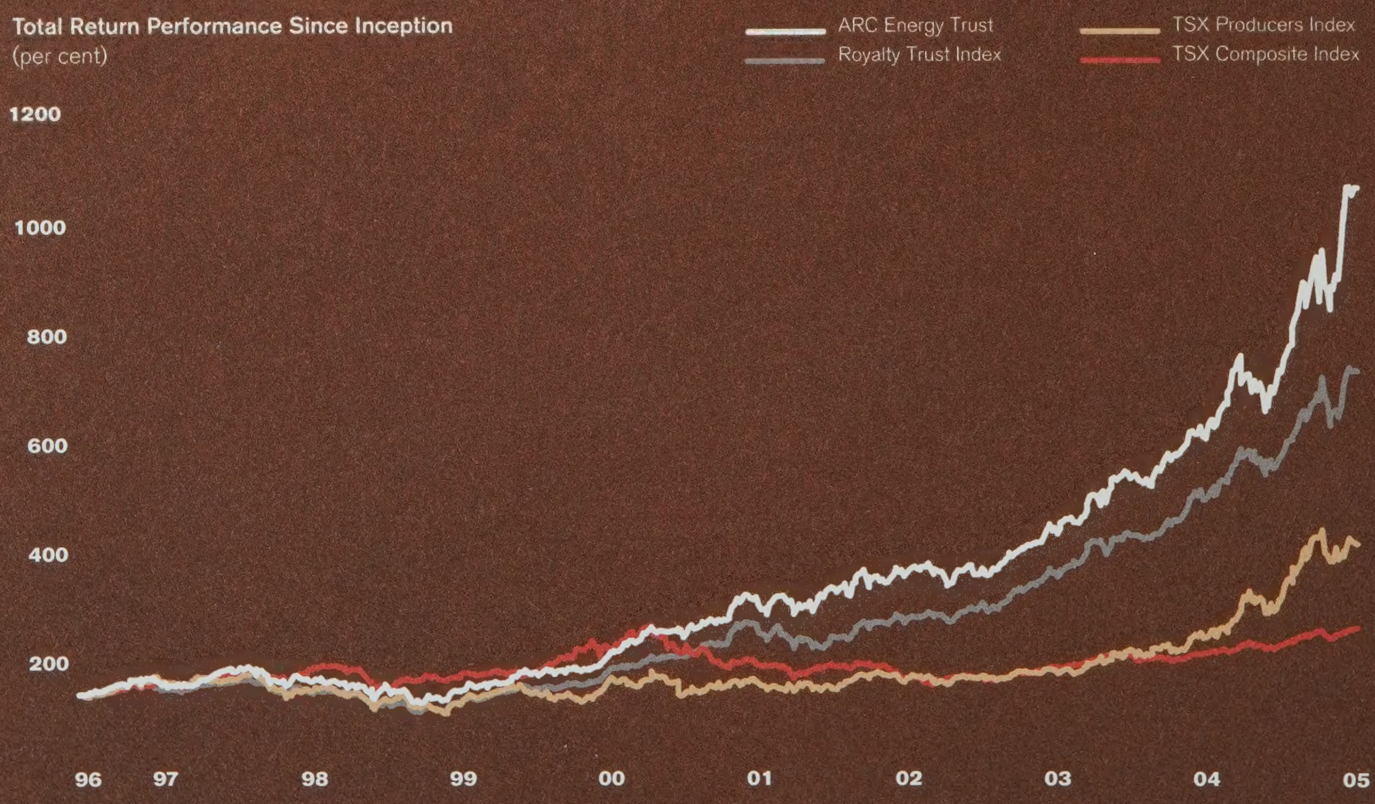

PROVEN PAST. PROMISING FUTURE.
ARC ENERGY TRUST
2005 ANNUAL REPORT

SIGNIFICANT FINANCIAL GROWTH

ARC ENERGY TRUST ("ARC" OR "THE TRUST") HAS CONSISTENTLY OUTPERFORMED THE ROYALTY TRUST INDEX, THE TSX COMPOSITE INDEX AND THE TSX PRODUCERS INDEX. AS OF DECEMBER 31, 2005 ARC'S ANNUAL RETURN WAS 62 PER CENT AND COMPOUND ANNUAL TOTAL RETURNS SINCE INCEPTION HAVE AVERAGED 28 PER CENT. ARC REMAINS COMMITTED TO GENERATING SUPERIOR RETURNS AND LONG-TERM VALUE.

ARC ENERGY TRUST UNITS TRADE ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL AET.UN ALONG WITH ITS EXCHANGEABLE SHARES UNDER THE SYMBOL ARX.

Total Return Performance Since Inception
(per cent)



ARC Energy Trust, located in Calgary, Alberta is one of Canada's largest conventional oil and gas royalty trusts. As an operating oil and gas company structured as a royalty trust, we acquire and develop long-life, lower declining oil and gas properties in western Canada. Our unitholders receive a monthly cash distribution from the Trust's producing oil and gas assets owned by ARC Resources Ltd.

Since inception our message and our mission have been consistent: utilize our excellent managerial and technical expertise to maximize value to our unitholders. We have done this through the acquisition and development of a portfolio of high quality, long-life assets. We have built a team that has the skills required to manage and exploit our asset base for the benefit of our unitholders.

PROMISING FUTURE

ARC WILL CONTINUE TO MANAGE ITS BUSINESS TO PROVIDE UNITHOLDERS WITH SUPERIOR RETURNS OVER THE LONG-TERM.

This 2005 Annual Report contains forward-looking statements that may be identified by words like "outlook," "estimates" and similar expressions. These forward-looking statements are based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. Actual results could differ materially as a result of changes to ARC's plans, the impact of changes in commodity prices, general economic, market and business conditions as well as production development and operating performance and other risks associated with oil and gas operations.

ARC ENERGY TRUST 2005 FINANCIAL HIGHLIGHTS

Year ended December 31	2005	2004
FINANCIAL		
(Cdn$ thousands, except per unit, per boe and per cent amounts)		
Revenue before royalties	**1,165,197**	901,782
Per unit (1)	**6.10**	4.85
Per boe (5)	**56.75**	43.32
Cash flow (2)	**639,511**	448,033
Per unit (1)	**3.35**	2.41
Per boe (5)	**31.15**	21.58
Net income	**356,935**	241,690
Per unit (8)	**1.90**	1.32
Cash distributions	**376,566**	329,977
Per unit (8)	**1.99**	1.80
Payout ratio	**59%**	74%
Net debt outstanding (3)	**578,086**	264,842
OPERATING		
Production		
Crude oil (bbl/d)	**23,282**	22,961
Natural gas (mcf/d)	**173,800**	178,309
Natural gas liquids (bbl/d)	**4,005**	4,191
Total (boe/d) (5)	**56,254**	56,870
Average prices		
Crude oil ($/bbl)	**61.11**	47.03
Natural gas ($/mcf)	**8.96**	6.78
Oil equivalent ($/boe) (5)	**56.54**	43.13
Netback ($/boe) (5)		
Commodity and other revenue (before hedging)	**56.75**	43.32
Transportation costs	**(0.70)**	(0.71)
Royalties	**(11.46)**	(8.51)
Operating costs	**(6.93)**	(6.71)
Netback (before hedging)	**37.66**	27.39

(1) Per unit amounts are based on weighted average units plus units issuable for exchangeable shares at year end.

(2) Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and expenditures on site restoration and reclamation.

(3) The net debt outstanding excludes amounts related to commodity and foreign exchange contracts.

Year ended December 31	2005	2005	2004
RESERVES (7)	**Gross Reserves**	**Company Interest Reserves**	
Proved reserves			
Crude oil and NGLs (mbbl)	**129,169**	**129,745**	95,734
Natural gas (bcf)	**582.6**	**595.7**	589.4
Total oil equilavent (mboe)	**226,273**	**229,033**	193,973
Proved plus probable reserves			
Crude oil and NGLs (mbbl)	**162,695**	**163,385**	123,226
Natural gas (bcf)	**726.6**	**741.7**	724.5
Total oil equivalent (mboe)	**283,795**	**286,997**	243,974
FINDING, DEVELOPMENT AND ACQUISITION COSTS ($/boe) (6)			
Including Future Development Capital			
Current year		**16.09**	19.14
Three year average		**13.50**	11.65
Excluding Future Development Capital			
Current year		**13.64**	13.76
Three year average		**11.00**	9.30
TRUST UNITS (thousands)			
Units outstanding, end of year		**199,104**	185,822
Units issuable for exchangeable shares		**2,935**	2,982
Total units outstanding and issuable for exchangeable shares, end of year		**202,039**	188,804
Weighted average units (4)		**188,237**	183,123
TRUST UNIT TRADING STATISTICS			
(Cdn$, except volumes) based on intra-day trading			
High		**27.58**	17.98
Low		**16.55**	13.50
Close		**26.49**	17.90
Average daily volume (thousands)		**656**	420

(4) Excludes exchangeable shares.
(5) Barrels of oil equivalent (boes) may be misleading, particularly if used in isolation. In accordance with NI-51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to boes throughout this annual report are based on a conversion ratio of 6:1.
(6) Based on proved plus probable company interest reserves before royalties.
(7) Gross reserves include the company working interest before deduction of royalty obligations and do not include royalty interests. Company interest reserves are the company interest plus the royalty interest prior to the deduction of royalty obligations.
(8) Per unit amounts (with exception of per unit distributions) are based on weighted average units.

MESSAGE TO OUR UNITHOLDERS

On July 11, 2006, ARC will celebrate its 10th anniversary. Investors who participated in that original $10 initial public offering have received $16.23 per unit (including the January 15, 2006 distribution) in distributions and have seen their units appreciate in price to $26.49 on December 31, 2005, which represents a compound annual return of 28 per cent over nine and one-half years. We have seen our production base grow from 9,566 boe per day in 1996 to 56,254 boe per day in 2005 and our employee count grow from just a handful at inception to the 305 we have today. With our history of proven performance we have delivered exceptional value to our unitholders; more importantly, we believe that the assets we have accumulated and the opportunities that exist for material incremental value creation within those assets have positioned ARC for an even more promising future.

Since inception, we have believed that high quality, long-life assets should comprise the core of our portfolio. Some of the first assets that helped create the Trust are in the Pembina area in Alberta, an area well known for these key attributes. Building upon this solid foundation, ARC's evolution into a technically oriented oil and gas producer truly began with the acquisition of Startech Energy in 2001 and was solidified with the acquisition of Star Oil and Gas Ltd. in 2003. ARC's most recent 2005 acquisitions of assets in the Pembina and Redwater areas continue this legacy and perfectly fit ARC's criteria to acquire assets with significant upside potential that time, technology enhancements and a positive commodity price environment will allow us to capitalize on.

During 2005, ARC's unitholders enjoyed the most profitable year in the Trust's history, with an annual total return of 62 per cent – the second highest return in the conventional oil and gas trust sector. This stellar performance was due in no small part to record oil and natural gas prices during the year. The price of West Texas Crude ("WTI") oil traded in a range of US$41.60 per barrel to an unprecedented high of US$70.50 per barrel and averaged US$56.61 per barrel during 2005. North American natural gas traded in a range of Cdn$5.90 per GJ at AECO to Cdn$14.00 per GJ during the year and averaged Cdn$8.36 per GJ. This strong commodity price environment resulted in an average total return in the sector of 37 per cent. The fact that ARC's performance exceeded the sector average by 60 per cent indicates that something beyond commodity prices accounted for our stellar performance.

Last year marked a major milestone in the evolution of the Canadian royalty trust and income fund sector when Standard and Poors announced that royalty trusts and income funds would become eligible for inclusion in their benchmark index. This opened the door for significant incremental institutional interest in the sector. For a sector that has traditionally traded on yield, the focus has shifted as this new group of investors are concerned with quality of assets, cost structure and management expertise. In each of these areas, ARC stands tall. In the second quarter of 2005, a leading independent research firm ranked ARC as number one in terms of asset quality among large cap trusts. This ranking was re-affirmed in a January 2006 updated review of the sector. ARC's market performance in 2005 reflected the recognition of ARC as one of the leading trusts in the sector, regardless of which measure one uses to make such an assessment.

The impact of high commodity prices was clearly evident in the Trust's financial results for 2005. Revenue before hedging was $1.17 billion, cash flow totaled $640 million, distributions were $377 million and net income was $357 million, all new records for the Trust. There are many implications to this record cash flow environment for the Trust and the industry as a whole. Utilization rates measuring the availability of people, equipment and rigs are running at all time high rates, stretching the oil and gas industry to its limits. The well count for the Canadian oil and gas sector reached an all time high of 21,999 well completions. With utilization rates at all time highs, costs are escalating significantly across the sector. Despite these

upward cost pressures, ARC's operating costs in 2005 were $6.93 per barrel of oil equivalent, an increase of just 3.3 per cent from 2004. This is a significant achievement when considering service and supply costs increased between five and 20 per cent for many of the services ARC utilizes in the field.

Economic Environment

Forecasts for commodity prices from analysts and economists of major banks remain bullish for 2006 for various reasons and it appears that we can expect another eventful year with regards to energy prices. Various economic, weather related and geo-political factors kept the markets jittery and quick to react to news in 2005, and we expect the same in 2006.

All of the uncertainties that can affect crucial oil and gas supply around the globe have raised the threshold for oil prices so that US$50.00 WTI has become an acceptable norm and prices below that level would most likely be unsustainable. Following this Message to Unitholders, we provide a list of 10 factors that we believe will be important themes influencing commodity prices in 2006.

Acquisitions

On December 6, 2005, ARC announced two major long-life asset acquisitions along with an accompanying equity financing. ARC purchased shares in wholly owned subsidiary companies of Imperial Oil Resources and ExxonMobil Canada Energy that owned a 45.57 per cent working interest in the North Pembina Cardium Unit ("NPCU") and of Imperial Oil Resources that owned a principal interest in the Redwater oil field in central Alberta. ARC funded these acquisitions initially with debt and then repaid a portion of the debt with the proceeds of the equity offering.

The assets purchased are legacy assets that comprise two of the largest light oil fields in western Canada. To date, over a billion barrels have been recovered from these fields and ARC estimates 900 million barrels remain unrecovered – approximately 500 million barrels attributable to ARC. The acquired assets fit ARC's profile perfectly. They are long-life, light oil assets with potential to add to ARC's production for the long-term. The assets have a 20 year reserve life index and have increased ARC's reserves by approximately 16 per cent and reserves per unit by approximately 10 per cent. The Trust's proved plus probable reserve life index has increased 5.7 per cent to 12.9 years, the longest in our history.

The Pembina NPCU asset is in an area that ARC knows well. Over the years, ARC has amassed large holdings in the area - when ARC was formed in 1996, it began its operations with ownership in properties in the Pembina field. Nine years later, the Berrymoor Cardium Unit, the MIPA blocks, and the Lindale Cardium Unit are still key properties for ARC. Earlier in 2005, ARC purchased additional interests in the Berrymoor Unit and the Buck Creek property and ARC now operates all of its principal assets in the Pembina field. Over the years, ARC has proven its ability to extract incremental value in the Pembina area. The acquisition of the NPCU interest enhances our interest in this oil producing area and provides for a promising future.

ARC now has a resource base of over 750 million barrels of light and medium oil that is not expected to be recovered under current plans. None of this resource is currently reflected in our reserves estimates. Time, commodity prices and developments in technology will all play a role in determining how much of this oil will ultimately be recovered. A large percentage of this resource is in Redwater, Pembina and southeastern Saskatchewan – all areas that we believe to be amenable to the application of enhanced recovery techniques such as CO_2 miscible floods to recover additional oil from our resource base. Two of the largest CO_2 floods in Canada are at the Weyburn and Midale oil fields in Saskatchewan; ARC has an ownership interest in both these fields and will be actively looking to apply its learned expertise from these fields to other assets where CO_2 recovery techniques may prove beneficial. In particular, we believe Redwater is a prime candidate for a

CO_2 flood and was acquired with that future potential as a primary consideration.

It is important to note that ARC did not include any value for CO_2 upside potential in the acquisition economics for these properties. The acquisition metrics were based on the production currently associated with these fields and any future upside associated with enhanced recovery techniques will be a direct uplift to ARC. The implementation of a CO_2 flood and an associated increase in production from Pembina and Redwater will take time – perhaps three to five years or longer; however, ARC has always been a long-term thinker regarding its assets and these projects are expected to play a significant role in our future.

Risk Management

We have always believed that protecting the stability of our distributions is very important. ARC began executing a new hedging strategy in late 2004 that primarily focused on the purchase of puts to minimize ARC's downside on a portion of its production, while providing full participation in price increases. Through this strategy, ARC's hedging cost will be no higher than the premium paid for these transactions, which is known when it enters into the contracts. ARC believes that this strategy is like buying insurance – it protects a portion of ARC's production from any unexpected downside that could materialize over the course of a year due to world events beyond its control, but leaves that production open to the full upside in the event of material upward price spikes. Though ARC did collapse most of its fixed hedge contracts in late 2004, it still had a few contracts in place that were capped transactions at a fixed price considerably below 2005 prices and as a result ARC incurred cash hedging losses of $87.6 million. These large losses are behind ARC as it carries on with its current hedging strategy, which allows ARC to participate in price upside on its production. The one exception to this strategy is a three-way collar transaction which will remain in effect through 2009 on 5,000 boe per day of production associated with the NPCU and Redwater acquisitions that limits ARC's full participation in price increases to US$90 but provides downside protection at US$55.00. The average cost of this price protection over the life of the contract is US$0.91 per barrel. This was done to protect the projected returns from this acquisition as the acquired production carries materially higher operating costs than our base production and we believe that it is important to protect the price and hence our returns over the next four years.

In Memoriam

I acknowledge with much regret and sadness that ARC lost an important member of its Board of Directors in 2005. Mr. John Beddome passed away on May 10, 2005. He was a member of ARC's Board since inception and contributed his wealth of knowledge and experience in the oil and gas industry to ARC and the community at large. His contribution to ARC's Board will be missed.

New Board Member

ARC is pleased to have added Mr. Herb Pinder to its Board of Directors effective January 1, 2006. Mr. Pinder brings an extensive business background to ARC covering several industries and a broad knowledge of corporate governance gained through his experience as a director on various public company boards over the last 20 years.

Mr. Pinder holds a Bachelor of Arts degree from the University of Saskatchewan, an LL.B from the University of Manitoba and an MBA from Harvard University Graduate School of Business. Currently, Mr. Pinder is the President of the Goal Group, a private equity management firm located in Saskatoon, Saskatchewan.

I know Mr. Pinder will make a strong contribution to ARC and I look forward to working closely with him in the future.

The Future

The future is not without its challenges. As costs continue to increase in 2006, it will be challenging for ARC to mitigate rising operating costs and General and Administrative costs ("G&A costs"). We experienced a 28 per cent cash G&A cost increase in 2005 as ARC needed to respond aggressively with its compensation programs to retain its employees in an industry that is currently unable to fill over 1,000 positions across various technical disciplines. Significant additional G&A cost increases are also expected for 2006. Our skilled and dedicated employees have delivered ARC's proven past and we believe they will be the key to delivering on the promising future that exists for the Trust. ARC's strategy of acquiring high quality long-life assets and exploiting them to their full potential has stood the test of time and has resulted in an asset base that is widely recognized as being one of the best in the sector.

We believe we are only as strong as our people. The powerful combination of one of the highest quality technical teams in the industry and our opportunity rich assets provide us with a very promising future.

John Dielwart

JOHN P. DIELWART
PRESIDENT & CHIEF EXECUTIVE OFFICER

EXPERIENCED INDUSTRY LEADERSHIP
WE ARE ONLY AS STRONG AS OUR PEOPLE. THE POWERFUL COMBINATION OF ONE OF THE HIGHEST QUALITY TECHNICAL TEAMS IN THE INDUSTRY AND OUR OPPORTUNITY RICH ASSETS PROVIDE US WITH A PROMISING FUTURE.

10 THEMES AFFECTING COMMODITY PRICES IN 2006

These are 10 themes that we believe will shape the world's energy markets in 2006. How these themes play out will have a large impact on commodity prices during the year.

1. Renewed emphasis on demand growth.

Ever since hurricanes Rita and Katrina struck and momentarily pushed oil prices over $70.00 per barrel the market has been concerned about on demand growth for petroleum products.

Now there is growing acknowledgment that the world's economy can handle oil prices above $50.00 per barrel, or more. Asian economies like China and India are still growing aggressively and requiring increasing amounts of energy commodities to do so. This will not change appreciably in 2006. Nor will the growing appetite for petroleum—especially gasoline—change in the United States.

2. More flexing of NOC muscle.

National oil companies ("NOCs") control the vast majority of the world's oil and gas reserves. From Iran, to Venezuela, to Russia, state-controlled oil companies are more and more being used as extensions of the host government's policy and power. We should expect the use of oil and natural gas as a state-directed tool of influence to grow in 2006. Supply side NOCs see two broad objectives: (1) to use critical energy supplies as a means to achieve political aims; and (2) to extract as much economic value out of the commodities as possible. Russia's dispute with the Ukraine is the most recent example of how critical energy resources are being used to exert muscle and raise prices. The new Bolivian government is seeking to nationalize its large natural gas reserves, nullifying long-standing contracts, and imposing tighter fiscal regimes (i.e. higher prices) on its natural gas exports. OPEC countries are not alone in using energy commodities as tools to project national influence. It's not new that NOCs control much of the world's oil and gas. What is new is that a tight supply and demand balance allows even marginal players to exert substantial leverage on the consuming world.

3. Iran becomes a flashpoint.

Iran's Prime Minister has been very overt about his nation's nuclear ambitions. The prospect of an atomic Iran has western governments feeling very jittery. The prospect that Iran, a major oil and natural gas supplier, will turn into a geo-political flashpoint is a "known unknown." At 3.9 million barrels per day, Iran is the fourth largest producer of oil in the world. That's notable enough, but more importantly Iran controls the northern side of the Strait of Hormuz, the 50-kilometre-wide waterway through which flows almost 20 per cent of the world's daily oil supply. Kuwait, Iraq, Iran, Saudi Arabia, Bahrain, Qatar, all transport much of their oil through this choke point. In addition, Iran boasts the second largest natural gas reserves in the world, after Russia.

Iran has publicly stated that it will use its oil supplies as a potential lever in the current nuclear standoff.

4. Increasing recognition of concentration risk.

Hurricanes Rita and Katrina awoke people to the risks of having too much energy infrastructure located in a concentrated geographic location. The recent Russia-Ukraine spat awoke Europeans of being too dependent on a big supplier. With the supply and demand balance for oil remaining tight through 2006 and beyond, markets will be increasingly sensitive to concentration risk; in other words, this year there will be a heightened awareness that too much critical energy supply or infrastructure is located in too few places.

5. Shortfall in oil production growth expectations.

Some influential agencies and consulting firms are calling for non-OPEC supply additions to add up to 1.4 million barrels per day this year. That's an aggressive number, given that achieving one million barrels per day has been difficult over the past several years. As well, over half the non-OPEC additions in the past three years have come from Russia. The Russians have publicly stated that their production growth has fallen to two per cent, or about 180,000 barrels per day. We think the market is going to be disappointed with how much new, non-OPEC oil comes on line in 2006. Additions may well be only 600,000 barrels per day, instead of the 1.4 million barrels the market is expecting.

6. OPEC will defend $50.00 barrels per day and above.

Seasonal factors, like the low-demand second quarter, may momentarily pull oil prices back down into the low-fifty-dollar range. OPEC members will defend $50.00 per barrel as their floor.

7. Emergence of energy policies in Asia.

Rapidly growing Asian nations like India and China know that they must do something to mitigate their aggressively growing dependency on energy, especially oil. Last year, India's leadership began discussing a long-term, visionary energy policy. Energy policies have much more influence than market forces in effecting change, especially on the demand side. With prices remaining volatile in 2006, governments will start becoming more visible in addressing energy issues in Asia. But will North American policy makers follow?

8. Narrowing of the global natural gas price arbitrage.

In the past one of the biggest energy anomalies in the world has been the huge price gap between expensive natural gas markets, like the US and the UK, and other parts of the world. For example, when the price of natural gas at Henry Hub was $12.00 per mmbtu, in North Africa it was $3.00 per mmbtu. Markets quickly sniff out such 'arbitrage' opportunities and work to close the gap. The reason for the price anomalies is that natural gas is difficult to transport across long distances. Without pipeline access or liquefaction facilities, natural gas reserves in low value regions are 'stranded,' because the gas can't get to market. That's changing with the global construction boom in natural gas pipelines and liquefied natural gas ("LNG") facilities.

Many believe that cheaper natural gas from places like Trinidad, Qatar, Iran and Russia will eventually make it to North America, bringing US and Canadian prices down. There is no question that the arbitrage will eventually narrow as pipelines and LNG facilities are built. But it's much more likely that global natural gas prices will rise closer to North American prices, not the other way around. Similar to oil, global natural gas resources are heavily concentrated under NOC control, with Russia, Iran and Qatar holding the lion's share. What is the incentive of such countries to give their natural gas away at lower prices?

As long-term contracts expire, the global natural gas arbitrage will narrow over the coming years. And contracts may not mean much. NOCs representing both small and large producing countries have demonstrated their muscle. As they've done for oil, they will seek to extract as much value from natural gas as possible. We may see it happen this year.

9. A return to a normal trading ratio for natural gas.

In the first couple of months in 2006, the price of natural gas at Henry Hub has fallen by about 45 per cent, down to around $7.00 per mmbtu. Although some are viewing this as a price collapse, we see it as a return to normal. Gulf Coast production disruptions after last fall's hurricanes caused legitimate concern about natural gas supply in advance of winter, causing the normal WTI-to-Henry Hub price ratio of about 6.5x to narrow to 4.0x. A mild winter so far, combined with disruptions in industrial demand, have led to acceptable levels of natural gas to remain in storage. There may still be some cold spells and large storage withdrawals to come during the remainder of the winter season. Prices will rally and the WTI-to-Henry Hub ratio will narrow. But don't expect it to last. With oil at $60.00 per barrel, natural gas prices above $10.00 per mmbtu, as we experienced in 2005, are not sustainable.

10. North American gas markets will 'see' LNG.

There are half-a-dozen LNG receiving terminals that are likely to come on line in North America by the end of this decade. Up to 6 bcf per day of new natural gas will be supplied to our domestic markets. To this point, the time horizon for these facilities has been 'years away.' With the first of the facilities likely to come on line in 2007, the reality will start to become much closer for the market to grasp this year. As these new LNG facilities become more 'visible' to the market, the forward price curve for natural gas is likely to become more stable, and less influenced by near-term seasonal factors.

Cautionary Statement: "10 Themes Affecting Commodiy Prices in 2006" is provided by management of ARC Resources and contains projections, beliefs and other forward looking statements. Such statements are based on assumptions that involve a number of risks and uncertainties, including those referenced in this Annual Report in Management's Discussion and Analysis. Results may differ materially from such statements for a wide variety of reasons, including geopolitical events, and economic, market and business conditions. Investors should consult their own advisors in relation to any investment decisions.

PROMISING FUTURE – ENHANCED OIL RECOVERY

Background

Conventional oil production techniques only recover a fraction of the original oil in place ("OOIP"), in most circumstances leaving most of the oil still locked in the ground. Depending on the characteristics of the reservoir, initial production methods may only recover five to 20 per cent of the OOIP. Secondary recovery methods, such as injecting water into the reservoir may recover an additional 10 to 20 per cent, but still leave much of the oil behind. Oil companies have been searching for years for other techniques to get more of this valuable resource out of the ground. One of the techniques used is "miscible flooding."

Miscible Flooding

A miscible flood is a general term for recovery techniques that inject gases or liquids into a reservoir under such conditions that the injected materials dissolve into the oil. This changes the characteristics of the oil in the ground helping to break the bonds that trap the oil in the rock pore spaces thereby increasing the amount of oil that can be recovered. Typical injected liquids and gases include liquefied petroleum gas (such as ethane and propane), nitrogen under high pressure, and carbon dioxide (CO_2) under suitable reservoir conditions of temperature and pressure.

In the United States, the most commonly used substance for miscible displacement is carbon dioxide because it is readily available at a lower cost than liquefied petroleum gases. There are naturally occurring sources of CO_2 in Colorado that provide a low cost supply for the CO_2 flooding of oil fields. CO_2 miscible floods have been ongoing in the United States for more than 30 years with over 60 projects in operation today.

Canada

In Canada, where there are no large scale naturally occurring sources of high quality CO_2, most miscible floods have used liquefied petroleum gases, but as these have increased dramatically in price in recent years, oil and gas companies have looked for cheaper alternatives. The first large scale CO_2 miscible flood in Canada was the Weyburn field in southeast Saskatchewan. CO_2 flooding of this field started in 2000 and is expected to recover an additional 10 per cent of the OOIP. In 2005, CO_2 flooding started at a neighbouring field called Midale. Both of these fields have been developed because a low cost source of CO_2 is available as the US government provided subsidies to North Dakota Power to capture the CO_2 emissions from a coal gasification facility. ARC has a seven per cent working interest in the Weyburn field and a 15.5 per cent working interest in the Midale field.

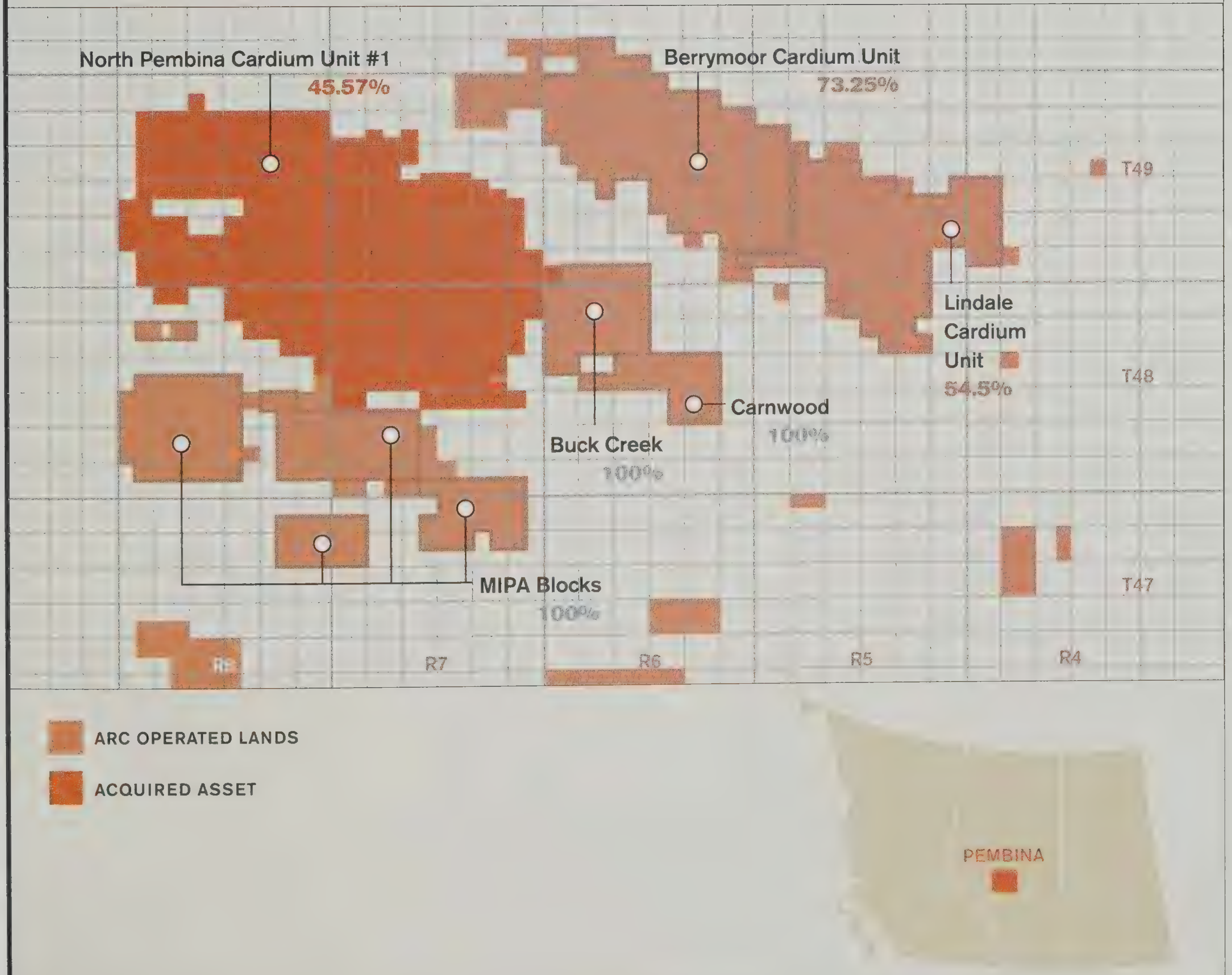
ARC's Future Potential

From inception, ARC has focused on obtaining assets that have large unrecovered resources. In addition to our interest in the Weyburn and Midale fields, we have other fields in Saskatchewan that also may be amenable to CO_2 flooding. In Alberta, ARC is the largest working interest owner in some of the most favourable areas in the Pembina field for this application. In addition, ARC believes that the recently acquired Redwater field is also a promising candidate for enhanced recovery through CO_2 injection. In total, ARC believes that between five and 15 per cent of the two billion barrels of OOIP in the Pembina and Redwater fields that ARC has an interest in may eventually be recovered should the right economic conditions exist.

What's Required?

For large scale CO_2 miscible flooding to occur in Alberta, a commercially viable source of CO_2 must be developed along with the associated pipeline infrastructure to transport the CO_2 to the applicable oil fields. As no naturally occurring sources are available, the most likely source will be to capture the CO_2 that is currently emitted by upgraders, refineries, petrochemical plants, coal fired power plants and other large industrial sources.

PEMBINA


North Pembina Cardium Unit #1
45.57%
Berrymoor Cardium Unit
73.25%
Lindale Cardium Unit
54.5%
Carnwood
100%
Buck Creek
100%
MIPA Blocks
100%
T49
T48
T47
R8
R7
R6
R5
R4
ARC OPERATED LANDS
ACQUIRED ASSET
PEMBINA

REVIEW OF OPERATIONS

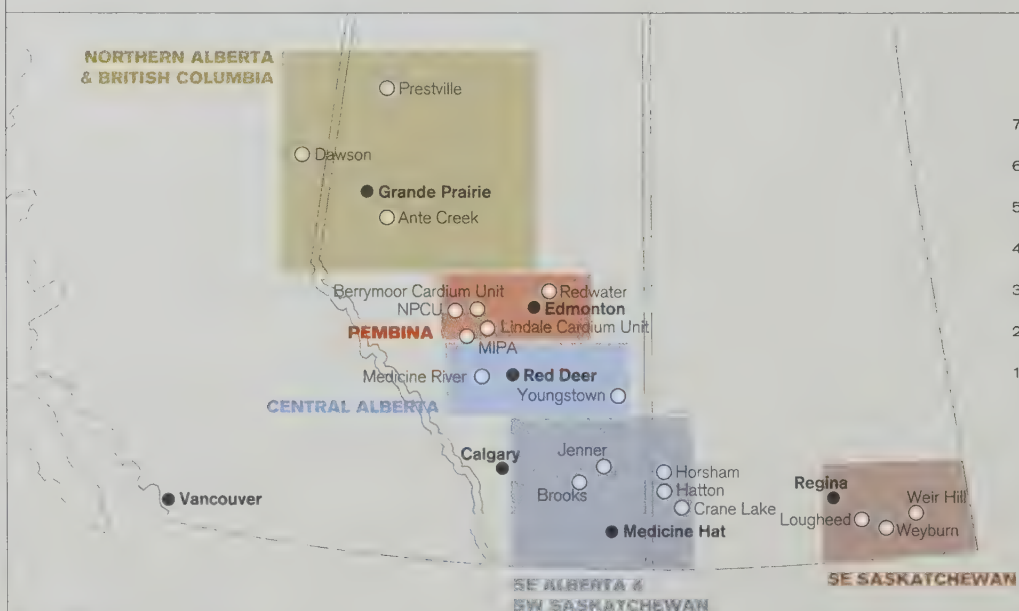
A substantial portfolio of high quality, long-life assets has consistently provided ARC with a large inventory of development opportunities. ARC's focus on opportunistically acquiring assets that have additional development potential embedded in them has proven itself time and time again. ARC has identified drilling and development opportunities within its asset base that are expected to sustain its production for the next 12 to 18 months and possibly longer, without being reliant on acquisitions.

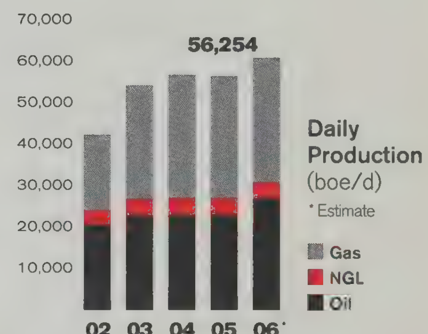
Production

For 2005, ARC averaged 56,254 boe per day of production, with 51 per cent coming from natural gas. Production increased during the year from 55,410 in the first quarter through to 59,120 in the fourth quarter as a result of ARC's capital development program and several key acquisitions. Production averaged over 61,000 boe per day during the month of December.

Area	Proved Plus Probable Reserves (gross)	Proved Plus Probable Reserves (company interest)	% of Total Proved plus Probable Reserves	2005 Average Production	% of Total Production
Central Alberta	22,350	22,665	7.9	8,041	14.3
SE Alberta/SW Saskatchewan	50,540	51,872	18.1	11,298	20.1
Northern Alberta & BC	83,398	84,433	29.4	18,286	32.5
SE Saskatchewan	45,682	45,733	15.9	10,676	19.0
Pembina	57,432	57,899	20.2	7,789	13.8
Redwater (1)	24,393	24,395	8.5	164	0.3
Total	**283,795**	**286,997**	**100.0**	**56,254**	**100.0**

(1) Redwater was acquired December 16, 2005. The December 2005 exit rate was 3,749 boe per day.





ARC expects that production in 2006 will average approximately 61,000 boe per day during the year composed of 31,000 bbl per day of oil and NGLs and 180 mmcf per day of natural gas, resulting in a portfolio that remains roughly balanced between oil and gas.

Capital Expenditures

In 2005, ARC executed the largest drilling program in its history. The $269 million capital program exploited opportunities in ARC's five core areas in western Canada and was primarily responsible for maintaining stable production volumes in 2005. Over $200 million of the capital budget was spent on drilling and completions. During the year, ARC drilled 250 gross wells (220 net wells) on operated properties; consisting of 68 gross oil wells, 180 gross natural gas wells, most of which were shallow gas wells, and two dry holes for a total success rate of 99 per cent. In addition, the Trust participated in 402 gross wells drilled by other operators.

For 2006, ARC is budgeting for a $340 million capital program. Approximately $40 million of this increase in the 2006 budget over 2005 is directly attributable to anticipated increases in the cost of supplies and services in the oil and gas sector. ARC expects to drill approximately 360 gross (263 net) wells, 80 of which will target oil and 280 will target natural gas. In ARC's non-operated properties we expect to participate in approximately 200 gross wells with net expenditures being approximately $60 million.

Finding and Development Costs ("F&D")

During 2005, ARC's exploitation and development activities added 15 mmboe of proved and 16 mmboe of proved plus probable reserves (including revisions). These activities replaced 76 per cent of ARC's 2005 production. In total, ARC drilled 250 operated wells with a 99 per cent drilling success rate.

BALANCED PRODUCTION APPROACH.
ARC HAS TRADITIONALLY MAINTAINED A PORTFOLIO ROUGHLY BALANCED BETWEEN OIL AND NATURAL GAS TO REDUCE THE RISK ASSOCIATED WITH FLUCTUATIONS BETWEEN OIL AND NATURAL GAS PRICES.

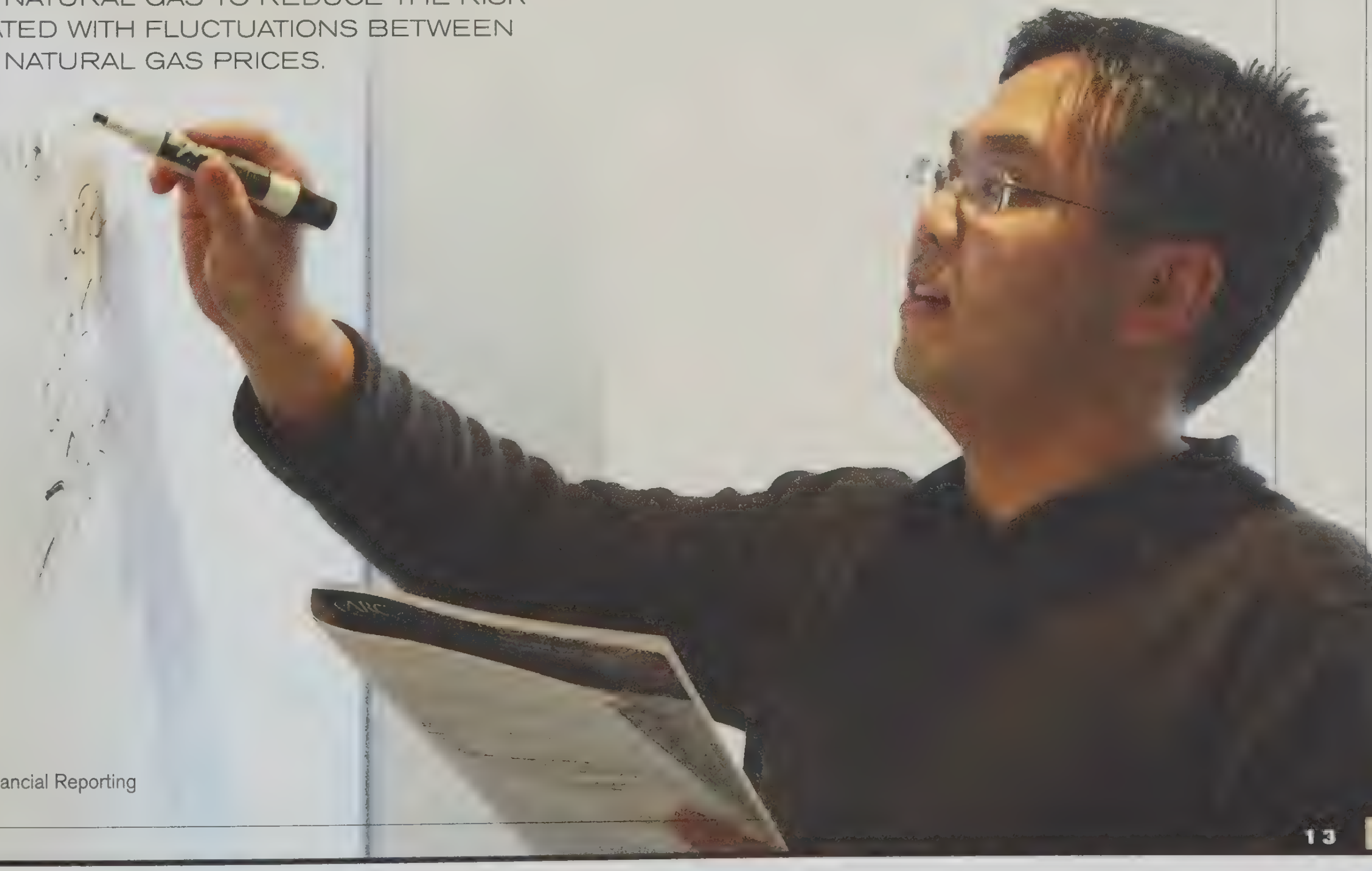
The most active areas were in ARC's shallow gas regions in southeastern Alberta and southwestern Saskatchewan where 157 successful gas wells were drilled. Gas drilling activity was also significant in the northern Alberta core area with the drilling of five vertical wells and ARC's first horizontal gas well in the Dawson area. As well, in the north, three successful multi-zone gas wells were drilled in the Pouce Coupe area.

ARC continued the development of several significant oil fields. The largest program was at Ante Creek where 17 wells were drilled proving up additional reserves and adding to the inventory of low risk infill drilling locations. In southeast Saskatchewan at Lougheed, seven horizontal wells and one vertical oil well were drilled, with numerous other wells drilled in ARC operated fields throughout the area. During 2005 ARC installed, implemented and commenced its waterflood in the Cranberry Slave Point D pool at Prestville.

ARC's non-operated properties underwent significant development activities, especially southeast Saskatchewan with the commencement of a commercial scale CO_2 enhanced oil recovery project at Midale as well as continued infill drilling and a slated expansion for the Weyburn Unit CO_2 enhanced oil recovery project.

Excluding future development capital ("FDC"), ARC's proved plus probable F&D costs for 2005 were $17.26 per boe. On a proved basis, ARC's F&D costs excluding FDC were $18.05 per boe.

Incorporating the net acquisitions during the year, ARC's proved finding, development and acquisition ("FD&A") costs, excluding FDC, were $15.60 per boe while proved plus probable FD&A costs were $13.64 per boe.



David Hwang
Supervisor, Financial Reporting

Left to right:

Tracey Rizopoulos
Senior Engineering Technologist

Rick Nakamoto
Manager, Geophysics

Ingram Gillmore
Manager, Engineering

Operating Costs

ARC continues to focus on maintaining safe, reliable and efficient operations in the field. ARC's operating costs for 2005 increased 3.3 per cent per boe from $6.71 per boe in 2004 to $6.93 per boe in 2005. This modest cost increase was achieved in spite of significant increases in service costs throughout the oil and gas sector. In 2006, ARC is budgeting operating costs of $8.65 per boe. The increase in operating costs for 2006 is due in part to continued increases in supply and service costs across the industry and to ARC's acquisition of the higher operating cost NPCU and Redwater properties in late 2005.

Recycle Ratio

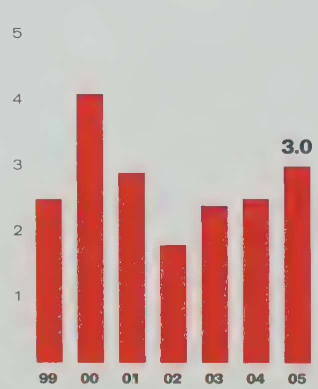
One measure of capital efficiency is "recycle ratio." The recycle ratio is determined by dividing the netback per boe by the FD&A costs per boe. It is a measure of how effectively an oil and gas company is investing its cash by calculating the dollars received for a barrel compared to the cost incurred to find and develop it. Generally, a recycle ratio of two or more is considered to be required to be profitable. The proved plus probable recycle ratio for 2005 using our three year average FD&A of $11 per boe was three.

Number of wells drilled by District

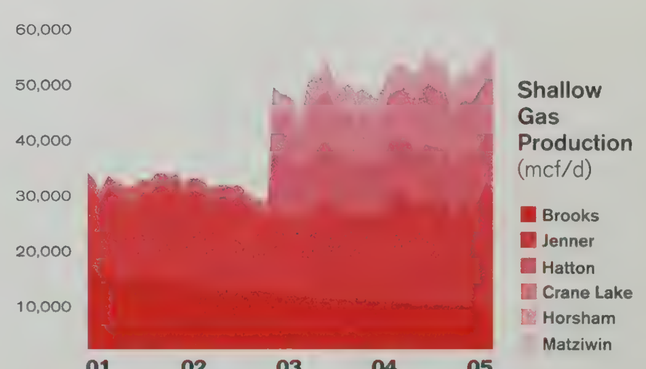
		Gross	Net
Pembina	Operated	25	19.0
Pembina	Non-Operated	25	2.8
SE Sask.	Operated	23	19.4
SE Sask.	Non-Operated	62	7.9
Northern AB & BC	Operated	32	30.9
Northern AB & BC	Non-Operated	65	4.1
SE AB, SW Sask.	Operated	160	143.3
SE AB, SW Sask.	Non-Operated	126	12.4
Central AB	Operated	10	7.1
Central AB	Non-Operated	124	10.4
Total		**652**	**257.3**

SE Alberta/SW Saskatchewan

The southeast Alberta and southwest Saskatchewan core area is our key shallow gas producing area. Shallow gas is an excellent trust asset – it provides low risk, stable production. The main shallow gas producing horizons are regional in nature, meaning that they are almost always present when you drill. Most of the production comes from horizons that are at "shallow depths" of between 375 and 675 metres, resulting in low drilling costs. The drilling costs and low operating costs contribute to attractive investment economics. At today's prices, a shallow gas well will pay itself out in 1.6 years and provide a return on investment of approximately 90 per cent.



Recycle Ratio



Shallow Gas Production (mcf/d)

Top 2005 producing properties

Property	Proved Plus Probable Reserves (company interest)	Production (boe/d)	Reserve Life Index (RLI)
Ante Creek	21,888	3,876	15
Lougheed	9,252	3,181	8
Jenner	16,348	2,668	17
Hatton	11,369	2,528	12
Pouce Coupe	5,807	2,411	7
Dawson	22,021	2,355	26
Weyburn Unit	12,888	1,782	20
Prestville	9,512	1,652	16
Brooks	4,607	1,328	10
Chinchaga	2,345	1,236	5
NPCU (1)	–	–	–
Redwater (1)	–	–	–

(1) NPCU and Redwater were acquired December 16, 2005. Based on December 2005 exit rates, NPCU and Redwater production was 1,500 boe per day and 3,749 boe per day, respectively.

The majority of ARC's 2005 drilling program took place in this area as ARC executed a 92-well drilling program in Jenner North and a 68-well drilling program at Hatton and Crane Lake. The drilling program was not without its challenges as extremely wet weather conditions in Alberta resulted in 14 wells from the proposed program being postponed. These wells were drilled in January 2006 and are expected to be on production in the first quarter of 2006. Average production increased four per cent in 2005 to 11,298 boe per day compared to 10,871 boe per day in 2004.

Despite drilling 280 shallow gas wells over the last two years, ARC still has a large inventory of wells to drill in this area. Most of ARC's shallow gas fields were originally developed with four wells per section (a square mile). ARC has been successfully infilling these fields to eight wells per section. ARC has at least another 500 wells to drill in its shallow gas area just to complete its infill drilling program to eight wells per section on all of its lands. Other operators are down-spacing to 12 wells per section – if ARC decides to infill drill to that level, it has over 1,000 additional wells to drill in the area. It is ARC's practice to typically drill around 150 wells per year in this area – hence there are many years of opportunities for drilling in this area.

Northern Alberta and British Columbia

The three most active areas in ARC's northern Alberta and British Columbia core area were Ante Creek, Dawson and Prestville. ARC drilled 17 vertical wells in Ante Creek, five vertical wells and one horizontal well in Dawson and placed five wells on production in Prestville. Ante Creek is a perfect example of how ARC's past discipline in seeking acquisitions that provide strategic development opportunities can enhance value to ARC's unitholders in the future. ARC's first purchase in the Ante Creek area was in January 2000. ARC drilled one well that year. In 2002, ARC drilled 19 wells, pushing the play to the south of the field. Through additional acquisitions in 2002, ARC was able to acquire 7,500 acres immediately to the south of the existing Ante Creek field. ARC's 2005 capital program in Ante Creek consisted of $30 million and focused on the drilling of 17 wells, which added almost five million boe of reserves.

STRATEGIC DEVELOPMENT OPPORTUNITIES
ARC SEEKS OUT ACQUISITION TARGETS THAT WILL PROVIDE IT WITH STRATEGIC OPPORTUNITIES FOR THE FUTURE GIVEN TIME, NEW TECHNOLOGY AND POTENTIALLY HIGHER COMMODITY PRICES.

Right:

Kevin Jones
Superintendent,
SE Alberta/SW Saskatchewan

One of the highlights of the year was ARC's use of new technology to increase recovery in its tight gas area of Dawson. ARC utilized a completion technique never before used in western Canada. The process places large "fractures" spaced equally along the length of a horizontal leg to effectively open more of the reservoir to contribute to the well's productivity. At $6.5 million, this well was expensive to drill and complete, however the dramatic increase in the deliverability of the well has justified the expenditure. The expertise garnered through this initial project will eventually translate into further horizontal drilling in Dawson with a lower cost to drill and complete, which should allow substantial future reductions in capital costs and potentially higher recoveries for that field. ARC installed additional compression facilities to increase production capacity.

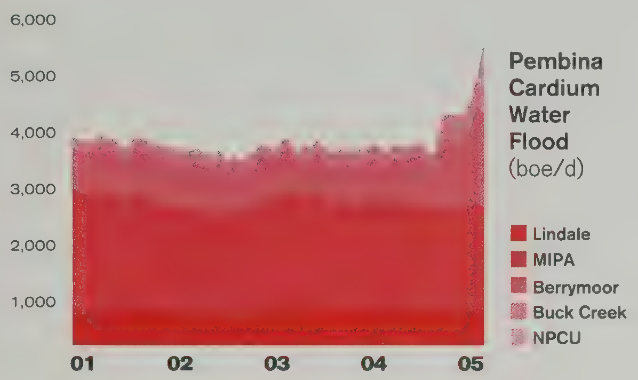
SE Saskatchewan

In southeast Saskatchewan, ARC increased its ownership in several key areas through the acquisition of a small private company and a minor property acquisition. Both of these assets were immediately adjacent to key ARC properties, consolidated ownership and added both production and new growth opportunities in Weirhill, Nottingham and Midale. Southeast Saskatchewan is a strategic component in ARC's portfolio as ARC has an ownership interest in two CO_2 enhanced oil recovery projects – one in Weyburn and one in Midale, which ARC sees as being key to unlocking value elsewhere in ARC's portfolio. At Weyburn, the CO_2 project was implemented in 2000 to increase the production from a field that was first developed in the 1960s. The CO_2 injection has been a success as production in that field has increased by 63.4 per cent from 2000 to 2005. ARC has recently increased its ownership at Weyburn to seven per cent. The CO_2 project at Midale was implemented in October 2005 and it is still too early to see or expect a response. Typically, it takes eight to 12 months before uplift in production is seen. Given that CO_2 flooding was piloted in this area, the risk of not meeting expectations is low. In Midale, ARC has a 15.5 per cent working interest. (A more detailed discussion on CO_2 recovery is included elsewhere in this annual report).

A total of 19 wells were drilled in southeast Saskatchewan in 2005 with production averaging 10,676 boe per day, slightly higher than 2004 production of 10,245 boe per day.

Pembina

When ARC was formed in 1996, properties in the Pembina area were key parts of ARC's asset base. Almost 10 years later, ARC still sees this light oil area as one of the most desirable areas of the province, despite it being on production for over 50 years. During 2005 ARC drilled 26 wells on its Pembina properties and spent more than $300 million to significantly increase its asset base in the area. In July, ARC consolidated its interest in the Berrymoor Unit and the Buck Creek oil pool through the purchase of additional working interest. ARC now owns a 100 per cent working interest in the Buck Creek oil pool and a 72.7 per cent working interest in Berrymoor, both of which it operates. After completing the Berrymoor acquisition, ARC undertook a 10-well drilling program, which resulted in a 33 per cent increase in oil production by year end. The following chart emphasizes the long-term stable nature of the Pembina area production and demonstrates the impact of ARC's recent acquisitions and drilling program.



In December 2005, ARC further strengthened its position in the Pembina area by acquiring a 45.57 per cent working interest in NPCU. NPCU is a key addition to ARC's holdings in this area as it provides ARC with a large critical mass of operations in the Pembina area. NPCU is adjacent to ARC's existing operations. ARC believes that the Pembina area is amenable to tertiary recovery techniques, such as CO_2 miscible floods. By consolidating its interests in Pembina, ARC is well positioned to implement CO_2 miscible floods in the area and achieve substantial upside on production volumes and reserves.

DYNAMIC OPERATIONAL PERFORMANCE
IN 2005 ARC DRILLED A TOTAL OF 250 GROSS WELLS ON OPERATED PROPERTIES WITH A SUCCESS RATE OF 99 PER CENT.

Central Alberta

ARC had a busy year in central Alberta. A total of nine wells were drilled in the area along with numerous optimization activities and well tie-ins. These activities resulted in production of 8,041 boe per day for the area.

The highlight for central Alberta was the successful natural gas from coal ("NGC") pilot development undertaken during 2005 at Delburne. ARC began exploration and pilot testing of the Horseshoe Canyon Coal by drilling two development wells, followed by a further three wells for data collection purposes. Based on results from these initial projects and some extensive competitor activity in the area, ARC will be conducting a minimum 50-well drilling program in Delburne in 2006. This will be ARC's first commercial scale NGC development. Production is expected to reach approximately 2 mmcf per day (net) once all the wells from Phase I are on production. A similar Phase II project is planned for 2007. ARC is budgeting up to $28 million for NGC projects for 2006 and will start exploring opportunities for both Mannville coal and Ardley coals within its properties.

HEALTH, SAFETY AND ENVIRONMENT

ARC has a long-standing tradition of leadership in all of its business and operations activities. ARC has consistently maintained a disciplined approach in health, safety and environment issues and remains committed to operating in a socially responsible manner.

ARC participates in and contributes to the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program and is committed to reporting at the platinum level, which is the highest reporting level. CAPP defines stewardship as "analysis, planning, implementation, measurement and review of social, environmental and economic performance."

ARC continues to reduce its greenhouse gas ("GHG") emissions. From 1999 to 2005, ARC has achieved a 24 per cent reduction in production carbon intensity ("PCI") through facility maintenance improvements and production efficiencies. ARC is also registered with, and provides information to, the National Pollutant Release Inventory ("NPRI"). This federal initiative captures information on the release and transfer of key pollutants in communities across Canada. NPRI has become a reputable source of information available to the public on corporate environmental performance.

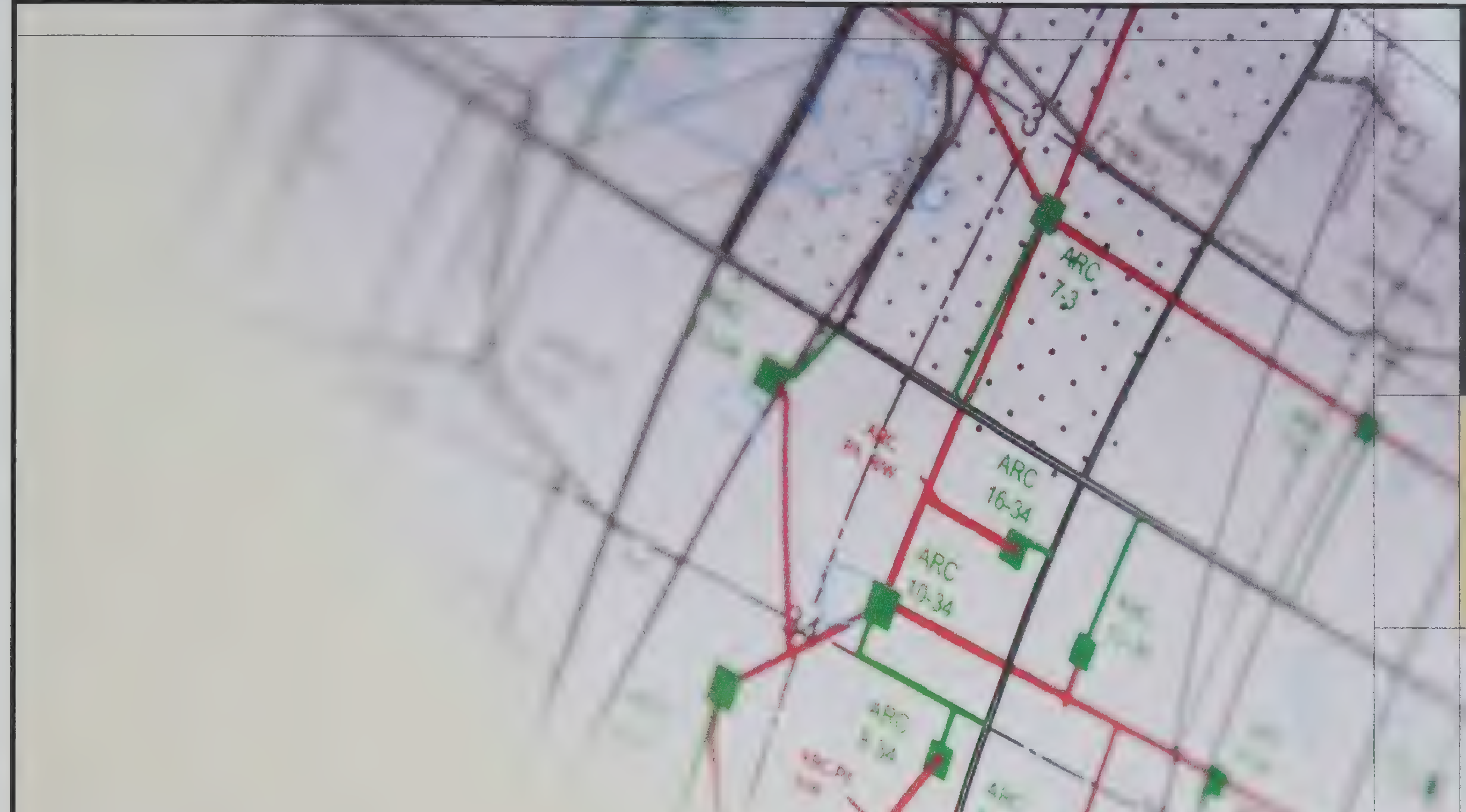
Production Energy Intensity ("PEI") is a key diagnostic as it illustrates efficiency of energy use on a per unit of production. ARC's current PEI is 1.28 GJ/m^3oe versus 1.47 GJ/m^3oe in 1999. This 13 per cent reduction demonstrates ARC's focus on efficient use of energy in its operations.

ARC effectively manages its liabilities through the controlled abandonment and reclamation of facilities, wells and leases. ARC maintains a reclamation fund to ensure that required funds are available for future reclamation of wells and facilities once they have reached the end of their economic life. ARC contributed $6 million to its reclamation fund in 2005 and

Left to right:

Yvan Chretien
Vice-President, Land

Terry Anderson
Vice-President, Operations



spent a total of $4.6 million. The fund balance currently stands at $23.5 million.

ARC conducts emergency response training on a regular basis in all of its operating fields to ensure a high level of response capability when placed in challenging situations. Scheduled exercises were held in all field areas in 2005, including a mock emergency exercise in the Pouce Coupe area with ARC field personnel, community emergency support services and regulatory agencies responsible for the Pouce Coupe area participating.

During peak activity times, ARC employs up to 500 contractors to implement its capital program across western Canada. It is important that ARC's contractors focus on safety. ARC held its second annual consultant's health and safety workshop in the spring of 2005. This annual workshop reinforces to contractors ARC's expectations for a safe work environment and provides an opportunity to review safe work practices and procedures, changes to regulatory requirements, and modifications to ARC's safety programs. One such program was the implementation of Mission Possible® safe driving modules. This safe driving program delivers a series of awareness and education modules to staff and contractors to improve driver knowledge and attitudes and to reduce the number of vehicle incidents. Since implementation, ARC has successfully reduced its vehicle incident frequency from 4.45 in 2004 to 0.46 in 2005, or less than one preventable vehicle incident per million kilometres driven.

ARC increased the number of safety audits performed on ARC operated facilities and lease sites in 2005 by 65 per cent over 2004. The audit program provides an opportunity to evaluate contractor performance and ensure ARC safety standards are engaged consistently and effectively at all sites.

ARC's health, safety and environment program and community involvement initiatives are explained in more detail on its website at www.arcenergytrust.com.

SUPPORTING THE COMMUNITY

ARC IS ACTIVELY INVOLVED IN CHARITABLE AND PHILANTHROPIC CAUSES BOTH IN CALGARY AND IN THE RURAL COMMUNITIES IN WHICH IT OPERATES. ARC IS A STRONG SUPPORTER OF THE UNITED WAY, ALBERTA CANCER FOUNDATION, ALBERTA CHILDREN'S HOSPITAL AND MANY COMMUNITY ORGANIZATIONS IN RURAL CENTRES.

RESERVES

ACQUISITIONS AND DISPOSITIONS

ARC was very active on the acquisition front during 2005 spending $598 million to purchase 48 mmboe of proved plus probable reserves. ARC's acquisitions were primarily focused on adding to its Pembina and southeast Saskatchewan core areas. The major strategic acquisition was the purchase of subsidiary companies of Imperial Oil Resources and ExxonMobil Canada Energy with a 45.57 per cent interest in NPCU.

A principal interest in the Redwater oil field in central Alberta was also acquired from a subsidiary of Imperial Oil Resources. This acquisition met ARC's objectives of adding long-term, stable producing assets to its existing high quality asset base. The big prize is the remaining oil in the reservoir that was not included in ARC's reserves assessment and ARC will strive to translate that potential into added value.

2005 Acquisition/Disposition Summary

	Purchase Price ($ millions)	Proved Plus Probable Reserves (mmboe)	Reserves Purchase Price ($/boe)	Production Rate (boe/d)	Production Purchase Price ($/boe/d)	Reserves Life Index (years)
Net acquisitions	598.3	48	12.47	7,457	80,229	17.6

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Under National Instrument 51-101 ("NI 51-101"), the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital required to bring the proved undeveloped and probable reserves to production. For continuity, ARC has presented FD&A costs calculated both excluding and including FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Incorporating the net acquisitions during the year, ARC's proved FD&A costs excluding FDC were $15.60 per boe, while proved plus probable FD&A costs were $13.64 per boe.

FD&A Costs – Company Interest Reserves (1)

	Proved	Proved Plus Probable
FD&A Costs Excluding Future Development Capital		
Exploration and development capital expenditures ($ thousands)	$ 268,834	$ 268,834
Exploration and development reserves additions including revisions (mboe)	14,892	15,573
Finding and development cost ($/boe)	$ 18.05	$ 17.26
Three year average F&D cost ($/boe)	$ 15.18	$ 12.76
Net acquisition capital ($ thousands)	$ 598,269	$ 598,269
Net acquisition reserves additions (mboe)	40,702	47,983
Net acquisition cost ($/boe)	$ 14.70	$ 12.47
Three year average net acquisition cost ($/boe)	$ 12.48	$ 10.24
Total capital expenditures including net acquisitions ($ thousands)	$ 867,103	$ 867,103
Reserves additions including net acquisitions (mboe)	$ 55,594	$ 63,556
Finding development and acquisition cost ($/boe)	$ 15.60	$ 13.64
Three year average FD&A cost ($/boe)	$ 13.30	$ 11.00

(1) In all cases, the F&D, or FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions. Boes may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

FUTURE DEVELOPMENT CAPITAL

NI 51-101 requires that FD&A costs be calculated including changes in FDC. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. The current high level of activity has resulted in increased capital costs throughout the industry that are now reflected in the estimates of future development costs effective December 31, 2005.

FD&A Costs Including Future Development Capital

	Proved	Proved Plus Probable
Exploration and development capital expenditures ($ thousands)	$ 268,834	$ 268,834
Exploration and development change in FDC ($ thousands)	$ 41,639	$ 79,197
Exploration and development capital including change in FDC ($ thousands)	$ 310,473	$ 348,031
Exploration and development reserves additions including revisions (mboe)	14,892	15,573
Finding and development cost ($/boe)	$ 20.85	$ 22.35
Three year average F&D cost ($/boe)	$ 17.64	$ 16.51
Net acquisition capital ($ thousands)	$ 598,269	$ 598,269
Net acquisition FDC ($ thousands)	$ 72,200	$ 76,160
Net acquisition capital including FDC ($ thousands)	$ 670,469	$ 674,429
Net acquisition reserves additions (mboe)	40,702	47,983
Net acquisition cost ($/boe)	$ 16.47	$ 14.06
Three year average net acquisition cost ($/boe)	$ 14.63	$ 12.36
Total capital expenditures including net acquisitions ($ thousands)	$ 867,103	$ 867,103
Total change in FDC ($ thousands)	$ 113,839	$ 155,357
Total capital including change in FDC ($ thousands)	$ 980,942	$ 1,022,460
Reserves additions including net acquisitions (mboe)	55,594	63,556
Finding development and acquisition cost including FDC ($/boe)	$ 17.64	$ 16.09
Three year average FD&A cost including FDC ($/boe)	$ 15.45	$ 13.50

Historic Company Interest Proved FD&A Costs

	2005	2004	2003	2002	2001	2000	1999
Annual FD&A excluding FDC	**$ 15.60**	$ 16.53	$ 10.78	$ 8.87	$ 11.35	$ 5.73	$ 5.86
Three year average FD&A excluding FDC	**$ 13.30**	$ 11.05	$ 10.69	$ 9.07	$ 8.06	$ 5.68	$ 5.76
Annual FD&A including FDC	**$ 17.64**	$ 20.46	$ 12.66	$ 10.03	$ 11.93	$ 7.56	$ 6.78
Three year average FD&A including FDC	**$ 15.45**	$ 13.02	$ 11.96	$ 10.16	$ 9.09	$ 7.15	$ 6.64

Historic Company Interest Proved Plus Probable FD&A Costs

	2005	2004	2003	2002	2001	2000	1999
Annual FD&A excluding FDC	**$ 13.64**	$ 13.76	$ 8.50	$ 9.27	$ 9.75	$ 5.16	$ 4.86
Three year average FD&A excluding FDC	**$ 11.00**	$ 9.30	$ 9.07	$ 8.21	$ 6.94	$ 4.95	$ 4.87
Annual FD&A including FDC	**$ 16.09**	$ 19.14	$ 10.54	$ 10.79	$ 10.41	$ 7.21	$ 5.77
Three year average FD&A including FDC	**$ 13.50**	$ 11.65	$ 10.52	$ 9.46	$ 8.04	$ 6.54	$ 5.81

RESERVES

Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with NI 51-101. This report contains several cautionary statements that are specifically required by NI 51-101. In addition to the detailed information presented here, more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) are included in ARC's Annual Information Form ("AIF").

Based on an independent reserves evaluation conducted by GLJ Petroleum Consultants Ltd. ("GLJ") effective December 31, 2005 and prepared in accordance with NI 51-101, ARC had proved plus probable reserves of 287 mmboe (1). Reserves additions from exploration and development activities (including revisions) were 16 mmboe, while 48 mmboe were added through acquisitions (net of minor dispositions), bringing the total additions to 64 mmboe. This represents 310 per cent of the 21 mmboe produced during 2005. As a result, year end 2005 reserves are 18 per cent higher than the 244 mmboe of proved plus probable reserves recorded at year end 2004.

Proved developed producing reserves represent 66 per cent of proved plus probable reserves (up from 63 per cent in 2004) while total proved reserves account for 80 per cent of proved plus probable reserves. Approximately 57 per cent of ARC's reserves are crude oil and natural gas liquids and 43 per cent are natural gas on a 6:1 boe conversion basis.

Net Present Value ("NPV") Summary 2005

ARC's crude oil, natural gas and natural gas liquids reserves were evaluated using GLJ's product price forecasts effective January 1, 2006 prior to provision for income taxes, interest, debt service charges, general and administrative expenses, hedging activity and certain abandonment and reclamation activity. It should not be assumed that the discounted future net production revenues estimated by GLJ represent the fair market value of the reserves.

NPV of Cash Flow Using GLJ January 1, 2006 Forecast Prices and Costs

NI 51-101 Net interest	Undiscounted ($ millions)	Discounted at 5% ($ millions)	Discounted at 10% ($ millions)	Discounted at 15% ($ millions)	Discounted at 20% ($ millions)
Proved producing	5,245	3,748	3,010	2,562	2,257
Proved developed non-producing	135	94	73	61	52
Proved undeveloped	741	466	315	221	159
Total proved	6,121	4,308	3,398	2,844	2,467
Probable	1,627	806	493	340	251
Proved plus probable	7,748	5,114	3,891	3,184	2,719

(1) Boes may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

At a 10 per cent discount factor, the proved producing reserves make up 77 per cent of the proved plus probable value while total proved reserves account for 87 per cent of the proved plus probable value. GLJ's price forecast utilized in the evaluation is summarized below.

GLJ January 1, 2006 Price Forecast

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/mmbtu)	Foreign Exchange ($US/$Cdn)
2006	57.00	66.25	10.60	0.85
2007	55.00	64.00	9.25	0.85
2008	51.00	59.25	8.00	0.85
2009	48.00	55.75	7.50	0.85
2010	46.50	54.00	7.20	0.85
2011	45.00	52.25	6.90	0.85
2012	45.00	52.25	6.90	0.85
2013	46.00	53.25	7.05	0.85
2014	46.75	54.25	7.20	0.85
2015	47.75	55.50	7.40	0.85
2016	48.75	56.50	7.55	0.85
Escalate thereafter at	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.85

The reserves have also been evaluated using constant prices and costs effective December 31, 2005. Following are the values determined using this constant price analysis.

NPV of Cash Flow Using December 31, 2005 Constant Prices and Costs

NI 51-101 Net Interest	Undiscounted ($ millions)	Discounted at 5% ($ millions)	Discounted at 10% ($ millions)	Discounted at 15% ($ millions)	Discounted at 20% ($ millions)
Proved producing	6,926	4,788	3,726	3,089	2,661
Proved developed non-producing	174	122	94	76	65
Proved undeveloped	1,069	693	482	350	261
Total proved	8,169	5,602	4,302	3,515	2,987
Probable	2,049	1,063	668	466	347
Proved plus probable	10,218	6,665	4,970	3,982	3,334

At a 10 per cent discount factor, the proved producing reserves make up 75 per cent of the proved plus probable value while total proved reserves account for 87 per cent of the proved plus probable value. The prices utilized in the constant price evaluation are summarized below.

Constant Prices at December 31, 2005

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/mmbtu)	Foreign Exchange ($US/$Cdn)
2006 and thereafter	$ 61.04	$ 68.27	$ 9.71	0.8577

Net Asset Value ("NAV")

The following NAV table shows what is normally referred to as a "produce-out" NAV calculation under which the current value of the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

In the absence of adding reserves to the Trust, the NAV per unit will decline as the reserves are produced out. The cash flow generated by the production relates directly to the cash distributions paid to unitholders. The evaluation includes future capital expenditure expectations required to bring undeveloped reserves on production. ARC works continuously to add value, improve profitability and increase reserves that enhance the Trust's NAV.

In order to determine the "going concern" value of the Trust, a more detailed assessment would be required of the upside potential of specific properties and the ability of the ARC team to continue to make value-adding capital expenditures. At inception of the Trust on July 16, 1996, the NAV was determined to be $11.42 per unit based on a 10 per cent discount rate; since that time, including the January 15, 2006 distribution, the Trust has distributed $16.23 per unit. Despite having distributed more cash than the initial NAV, the NAV as at December 31, 2005 was $16.62 per unit using GLJ prices and $21.92 per unit using constant prices and costs. NAV increased $5.19 per unit during 2005 after distributing $1.99 per unit to unitholders. Following is a summary of historical NAVs calculated at each of the Trust's year ends utilizing GLJ price forecasts.

Historical NAV – Discounted at 10 Per Cent

($ millions, except per unit amounts)	**2005**	2004	2003	2002	2001	2000	1999
Value of NI 51-101 net interest proved plus probable reserves (1)	**$ 3,891**	$ 2,389	$ 1,689	$ 1,302	$ 1,216	$ 945	$ 530
Undeveloped lands	**59**	48	50	20	22	6	12
Reclamation fund	**23**	21	17	13	10	10	7
Commodity and foreign currency contracts (2)	**(2)**	(12)					
Long-term debt, net of working capital	**(578)**	(265)	(262)	(348)	(289)	(109)	(125)
Asset retirement obligation	**(35)**	(23)	(27)	–	–	–	–
Net asset value	**$ 3,358**	$ 2,158	$ 1,467	$ 987	$ 959	$ 852	$ 424
Units outstanding (thousands)	**202,039**	188,804	182,777	126,444	111,692	72,524	53,607
NAV per unit	**$ 16.62**	$ 11.43	$ 8.03	$ 7.81	$ 8.59	$ 11.74	$ 7.92

(1) Proved plus probable in 2003, 2004 and 2005 is estimated in accordance with NI 51-101 while in prior years it represents established reserves (which represents proved plus risked probables).

(2) Commodity and foreign currency contracts were included in the value of proved plus probable reserves prior to 2004.

Reserves Life Index ("RLI")

ARC's proved plus probable RLI was 12.9 years at year-end 2005 while the proved RLI was 10.3 years based upon the GLJ reserves and ARC's 2006 production guidance of 61,000 boe per day. The following table summarizes ARC's historical RLI.

	2005	2004	2003	2002	2001	2000	1999	1998
Total proved	**10.3**	9.7	10.1	10.1	9.8	10.4	10.1	10.0
Proved plus probable (established reserves for 2002 and prior years)	**12.9**	12.2	12.4	11.8	11.5	12.1	12.0	11.9

Reserves Summary 2005 Using GLJ January 1, 2006 Forecast Prices and Costs

Company Interest (Working Interest + Royalties Receivable)

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2005 (mboe)	Oil Equivalent 2004 (mboe)
Proved producing	98,934	2,971	101,905	10,393	461.3	189,179	152,968
Proved developed non-producing	1,762	0	1,762	433	15.7	4,818	2,349
Proved undeveloped	13,866	40	13,906	1,346	118.7	35,036	38,656
Total proved	114,562	3,011	117,573	12,172	595.7	229,033	193,973
Proved plus probable	144,528	3,787	148,315	15,070	741.7	286,997	243,974

Gross Interest (Working Interest Before Royalties Payable)

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2005 (mboe)	Oil Equivalent 2004 (mboe)
Proved producing	98,844	2,692	101,536	10,192	448.2	186,435	150,188
Proved developed non-producing	1,760	0	1,760	433	15.7	4,816	2,346
Proved undeveloped	13,863	40	13,903	1,346	118.6	35,023	38,627
Total proved	114,467	2,732	117,199	11,970	582.6	226,273	191,160
Proved plus probable	144,414	3,457	147,871	14,824	726.6	283,795	240,788

Net Interest (Working Interest + Royalties Receivable - Royalties Payable)

	Light and Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Total Crude Oil (mbbl)	NGLs (mbbl)	Natural Gas (bcf)	Oil Equivalent 2005 (mboe)	Oil Equivalent 2004 (mboe)
Proved producing	88,083	2,725	90,808	7,358	380.1	161,509	128,508
Proved developed non-producing	1,559	0	1,559	314	12.4	3,944	1,899
Proved undeveloped	12,032	34	12,066	948	97.0	29,183	32,081
Total proved	101,674	2,758	104,432	8,621	489.5	194,637	162,488
Proved plus probable	127,813	3,458	131,271	10,713	609.0	243,482	204,357

Reserves Reconciliation

Company Interest Reserves (1)	Crude Oil (mbbl) Proved (2)	Crude Oil (mbbl) Probable (3)(4)	Natural Gas (bcf) Proved	Natural Gas (bcf) Probable (3)	NGLs (mbbl) Proved	NGLs (mbbl) Probable (3)	Total (mboe) Proved	Total (mboe) Probable (3)
Reserves at December 31, 1997	**18,948**	**5,207**	**127.7**	**20.5**	**7,459**	**759**	**47,690**	**9,383**
Acquisitions and divestments	2,465	648	(15.1)	(2.7)	(195)	(36)	(247)	162
Drilling and development	981	844	4.0	1.2	7	(104)	1,655	940
Production	(1,620)	–	(13.8)	0.0	(737)		(4,657)	–
Revisions	1,993	(1,570)	0.8	(0.6)	8	(23)	2,134	(1,693)
Reserves at December 31, 1998	**22,767**	**5,129**	**103.6**	**18.4**	**6,542**	**596**	**46,576**	**8,792**
Acquisitions and divestments	17,769	4,286	118.0	15.4	3,375	476	40,817	7,320
Drilling and development	1,992	631	5.8	1.7	204	1	3,168	912
Production	(3,069)	–	(24.3)	–	(981)	–	(8,100)	–
Revisions	536	204	0.7	1.7	(977)	232	(320)	713
Reserves at December 31, 1999	**39,995**	**10,250**	**203.9**	**37.1**	**8,163**	**1,304**	**82,141**	**17,737**
Acquisitions and divestments	18,650	3,860	47.7	8.0	1,911	328	28,517	5,527
Drilling and development	2,283	(693)	12.9	1.3	119	(25)	4,554	(497)
Production	(4,219)	–	(28.2)	–	(1,085)	–	(10,012)	–
Revisions	1,805	(268)	7.4	(3.8)	203	(166)	3,235	(1,057)
Reserves at December 31, 2000	**58,513**	**13,149**	**243.7**	**42.7**	**9,311**	**1,442**	**108,437**	**21,710**
Acquisitions and divestments	27,932	7,124	101.9	11.1	1,643	241	46,551	9,211
Drilling and development	2,641	275	12.7	3.1	437	81	5,191	865
Production	(7,449)	–	(42.0)	–	(1,282)	–	(15,736)	–
Revisions	1,057	(610)	14.3	(1.8)	(148)	(117)	3,295	(1,029)
Reserves at December 31, 2001	**82,695**	**19,937**	**330.5**	**55.0**	**9,962**	**1,649**	**147,739**	**30,757**
Acquisitions and divestments	5,270	729	36.6	2.0	574	(32)	11,944	1,027
Driling and development	1,574	224	8.4	1.8	129	28	3,097	545
Production	(7,539)	–	(40.1)	–	(1,270)	–	(15,485)	–
Revisions	3,764	(1,513)	20.8	(6.2)	1,108	(48)	8,345	(2,598)
Reserves at December 31, 2002	**85,764**	**19,377**	**356.2**	**52.6**	**10,503**	**1,597**	**155,640**	**29,731**
Exploration discoveries	–	–	1.1	0.3	2	–	182	45
Drilling extensions	2,108	(1,460)	4.3	(1.5)	103	(28)	2,935	(1,734)
Improved recovery	510	(495)	1.5	(0.2)	61	(18)	817	(546)
Technical revisions	3,136	3,872	29.2	14.0	143	306	8,145	6,511
Economic factors	(854)	4	(1.1)	–	(35)	1	(1,076)	5
Acquisitions	17,642	5,720	307.6	59.7	3,713	702	72,614	16,380
Dispositions	(9,852)	(2,043)	(38.8)	(4.7)	(874)	(98)	(17,196)	(2,917)
Production	(8,353)	–	(59.9)	–	(1,491)	–	(19,832)	–
Reserves at December 31, 2003	**90,101**	**24,975**	**600.0**	**120.2**	**12,125**	**2,462**	**202,229**	**47,475**
Exploration discoveries	235	59	1.9	0.8	9	2	565	202
Drilling extensions	941	428	6.3	2.1	198	64	2,194	842
Improved recovery	1,522	180	16.4	13.3	374	149	4,629	2,542
Technical revisions	833	(1,042)	10.4	(4.0)	795	72	3,362	(1,643)
Acquisitions	2,000	986	19.5	2.8	23	5	5,280	1,460
Dispositions	(4,843)	(945)	(12.8)	(3.8)	(598)	(102)	(7,570)	(1,674)
Economic factors	1,816	154	12.8	3.6	142	45	4,098	796
Production	(8,404)	–	(65.3)	–	(1,534)	–	(20,814)	–
Reserves at December 31, 2004	**84,200**	**24,794**	**589.4**	**135.1**	**11,534**	**2,697**	**193,973**	**50,000**
Exploration discoveries	–	–	5	2	60	15	828	257
Drilling extensions	493	54	15	11	325	151	3,308	1,995
Improved recovery	3,243	814	21	3	526	138	7,299	1,471
Technical revisions	139	(1,220)	7	(8)	(311)	(345)	962	(2,858)
Acquisitions	36,797	6,626	19	3	1,506	257	41,380	7,406
Dispositions	(397)	(63)	(1)	–	(68)	(15)	(679)	(125)
Economic factors	1,597	(263)	5	1	63	–	2,495	(184)
Production	(8,498)	–	(63)	–	(1,462)	–	(20,533)	–
Reserves at December 31, 2005	**117,573**	**30,742**	**596**	**146**	**12,173**	**2,898**	**229,033**	**57,963**

(1) Company interest reserves include working interests and royalties receivable.
(2) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2004 of 3,201 mbbl, drilling extensions of 46 mbbl, improved recovery of 4 mbbl, technical revisions of (23) mbbl, economic factors of 195 mbbl and production of (458) mbbl, leaving a closing balance of 3,011 mbbl.
(3) Probable reserves risked at 50 per cent for 1998 through 2002.
(4) Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2004 of 863 mbbl, drilling extensions of (26) mbbl, improved recovery of 1 mbbl, technical revisions of (84) mbbl, economic factors of 22 mbbl, leaving a closing balance of 776 mbbl.

Net Interest (Working Interest + Royalties Receivable - Royalties Payable) Reserves Reconciliation

	Crude Oil (mbbl)		Natural Gas (bcf)		NGLs (mbbl)		Total (mboe)	
	Proved (1)	Probable (2)	Proved	Probable	Proved	Probable	Proved	Probable
Reserves at December 31, 2004	73,340	21,375	485.4	111.0	8,251	1,992	162,488	41,869
Exploration discoveries	–	–	3.4	1.1	42	10	616	193
Drilling extensions	439	49	11.5	8.5	225	104	2,584	1,565
Improved recovery	2,853	707	17.7	2.2	365	90	6,169	1,157
Technical revisions	171	(987)	5.4	(5.7)	(201)	(263)	866	(2,203)
Acquisitions	34,200	6,191	13.0	2.2	1,035	178	37,395	6,740
Dispositions	(357)	(59)	(0.9)	(0.2)	(42)	(9)	(548)	(101)
Economic factors	954	(437)	4.3	0.4	24	(9)	1,691	(374)
Production	(7,167)	–	(50.3)	–	(1,077)	–	(16,624)	–
Reserves at December 31, 2005	104,432	26,839	489.5	119.5	8,621	2,093	194,636	48,846

(1) Heavy oil reserves reconciliation as a component of crude oil on a proved basis started with reserves at December 31, 2004 of 2,952 mbbl, drilling extensions of 41 mbbl, improved recovery of 4 mbbl, technical revisions of (8) mbbl, economic factors of 175 mbbl and production of (406) mbbl, leaving a closing balance of 2,758 mbbl.

(2) Heavy oil reserves reconciliation as a component of crude oil on a probable basis started with reserves at December 31, 2004 of 782 mbbl, drilling extensions of (23) mbbl, improved recovery of 1 mbbl, improved recovery of (23) mbbl, technical revisions of (75) mbbl, economic factors of 15 mbbl, leaving a closing balance of 699 mbbl.

Additional Oil and Gas Disclosure

For more information in relation to gross reserves, net resources, F&D costs and other items of oil and gas disclosure mandated by NI 51-101, reference is made to the Annual Information Form of the Trust, which will be filed on SEDAR (www.sedar.com) by March 31, 2006 and will also be available on ARC's website at www.arcenergytrust.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2005 and the audited consolidated financial statements and MD&A for the year ended December 31, 2004 and MD&A for the three quarters ended March 31, 2005, June 30, 2005 and September 30, 2005.

This MD&A is dated February 8, 2006.

Management uses cash flow, cash flow from operations and cash flow from operations per unit derived from cash flow from operating activities (before changes in non-cash working capital and expenditures on site reclamation and restoration) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

The following table reconciles the cash flow from operating activities to cash flow from operations which is used frequently in this MD&A:

($ thousands)	**2005**	2004
Cash flow from operating activities	**616,711**	446,418
Changes in non-cash working capital	**17,919**	(1,617)
Expenditures on site reclamation and restoration	**4,881**	3,232
Cash flow from operations	**639,511**	448,033

Management uses certain key performance indicators ("KPI's") and industry benchmarks such as operating netbacks ("netbacks"), total capitalization and finding, development and acquisition costs to analyze financial and operating performance. These KPI's and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements as to the Trusts internal projections, expectations or beliefs relating to future events or future performance within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995 and the Securities Act (Ontario). In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of ARC Energy Trust ("ARC" or "the Trust"). The projections, estimates and beliefs contained in such forward-looking statements are based on management's assumptions relating to the production performance of ARC's oil and gas assets, the cost and competition for services throughout the oil and gas industry in 2006 and the continuation of the current regulatory and tax regime in Canada, and necessarily involve known and unknown risks and uncertainties, including the business risks discussed in this MD&A, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. The Trust does not undertake to update any forward looking information in this document whether as to new information, future events or otherwise.

Highlights

(Cdn$ millions, except per unit and volume data)	2005	2004	% Change
Cash flow from operations	**639.5**	448.0	43
Cash flow from operations per unit (1)	**3.35**	2.41	39
Net income	**356.9**	241.7	48
Distributions per unit (4)	**1.99**	1.80	11
Payout ratio per cent (2)	**59**	74	(20)
Total daily production (boe/d) (3)	**56,254**	56,870	(1)

(1) Per unit amounts are based on weighted average units plus units issuable for exhangeable shares at year end.
(2) Based on cash distributions divided by cash flow from operations.
(3) Reported production amount is based on company interest before royalty burdens. Where applicable in this MD&A natural gas has been converted to barrels of oil equivalent ("boe") based on 6 mcf:1 bbl. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the well head. Use of boe in isolation may be misleading.
(4) Based on number of trust units outstanding at each cash distribution date.

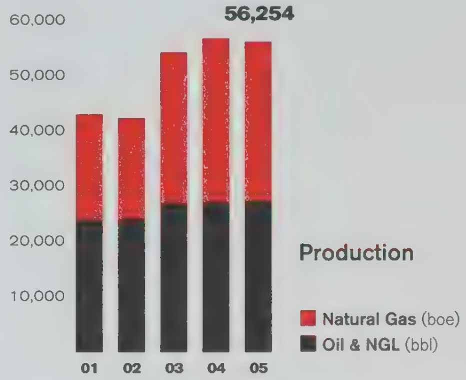
Cash Flow from Operations

Cash flow from operations increased by 43 per cent in 2005 to $640 million from $448 million in 2004. This increase was primarily the result of higher commodity prices. The cash flow from operations per unit increased 39 per cent to $3.35 per unit from $2.41 per unit in 2004. The 2005 cash flow from operations included a cash loss of $87.6 million on commodity and foreign currency contracts while 2004 cash flow included a loss of $86.9 million on commodity and foreign currency contracts.

The following table summarizes the variances in cash flow from operations and in cash flow from operations per unit between 2004 and 2005. It shows the variance is due mainly to increased commodity pricing, with some of the price increase being paid out in increased royalties and a small decrease in revenue because of the one per cent decrease in the volumes produced.

	($ millions)	($ per trust unit)	(% variance)
2004 Cash Flow from Operations	**$ 448.0**	**$ 2.41**	
Volume variance	(12.2)	(0.07)	(3)
Price variance	275.6	1.48	62
Cash losses on commodity and foreign currency contracts (1)	(0.6)	–	–
Royalties	(58.3)	(0.31)	(13)
Expenses:			
Transportation	0.5	–	–
Operating	(2.5)	(0.01)	(1)
Cash G&A	(6.0)	(0.03)	(1)
Interest	(3.6)	(0.02)	(1)
Taxes	(1.0)	(0.01)	–
Realized foreign exchange gain	(2.2)	(0.01)	–
Other	1.8	0.01	–
Weighted average trust units	-	(0.09)	(4)
2005 Cash flow from Operations	**$ 639.5**	**$ 3.35**	**39**

(1) Represents cash losses on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.



Production

Production volumes averaged 56,254 boe per day in 2005 compared to 56,870 boe per day in 2004. Production from the Redwater and North Pembina Cardium Unit ("NPCU") acquisitions were included starting on December 16, 2005 (these areas contributed 5,460 boe per day for the last 16 days of December 2005). The Trust exited 2005 with average daily production for the month of December in excess of 61,000 boe per day.

The Trust expects 2006 production to average 61,000 boe per day, an eight per cent increase over 2005.

Production	**2005**	2004	% Change
Crude oil (bbl/d)	**23,282**	22,961	1
Natural gas (mcf/d)	**173,800**	178,309	(3)
NGL (bbl/d)	**4,005**	4,191	(4)
Total production (boe/d) (1)	**56,254**	56,870	(1)
% Natural gas production	**51**	52	
% Crude oil and liquids production	**49**	48	

(1) Reported production for a period may include minor adjustments from previous production periods.

The following table summarizes the Trust's production by core area:

	2005				2004			
Core Area (1)	**Total** (boe/d)	**Oil** (bbl/d)	**Gas** (2) (mmcf/d)	**NGL** (bbl/d)	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	**8,041**	**1,364**	**30.2**	**1,641**	9,295	2,003	32.6	1,856
Northern AB & BC	**18,286**	**6,026**	**65.3**	**1,381**	19,026	5,733	71.1	1,441
Pembina & Redwater	**7,953**	**4,166**	**17.7**	**832**	7,433	3,742	17.5	772
S.E. AB & S.W. Sask.	**11,298**	**1,499**	**58.7**	**15**	10,871	1,658	55.2	14
S.E. Sask.	**10,676**	**10,227**	**1.9**	**136**	10,245	9,825	1.9	108
Total	**56,254**	**23,282**	**173.8**	**4,005**	56,870	22,961	178.3	4,191

(1) Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, S.E. is southeast, S.W. is southwest.
(2) Rounding of the gas conversion at 6:1 mmcf can result in totals not summing exactly.

Commodity Prices

Benchmark prices	2005	2004	% Change
AECO gas ($/mcf) (1)	**8.45**	6.79	24
WTI oil (US$/bbl) (2)	**56.61**	41.43	37
US$/Cdn$ foreign exchange rate	**0.83**	0.77	8
WTI oil (Cdn$/bbl)	**68.52**	53.81	27

(1) Represents the AECO monthly posting.
(2) WTI represents West Texas Intermediate posting as denominated in US$.

Oil and gas prices reached historic highs in 2005. The strength of the Canadian dollar served to partially offset the impact of higher US denominated oil prices. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than five per cent of the Trust's liquids production. Overall the price of WTI oil in Canadian dollars increased by 27 per cent over the prior year to $68.52 versus $53.81 in 2004.

Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged $8.45 per mcf in 2005 compared to $6.79 per mcf in 2004. ARC's realized gas price, before hedging, increased by 32 per cent to $8.96 per mcf compared to $6.78 per mcf in 2004. ARC's realized gas price is based on prices received at the various markets in which the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators.

Prior to hedging activities, ARC realized $56.54 per boe in 2005, a 31 per cent increase over the $43.13 per boe received prior to hedging in 2004.

The following is a summary of realized prices :

ARC Realized Prices

	2005	2004	% Change
Oil ($/bbl)	**61.11**	47.03	30
Natural gas ($/mcf)	**8.96**	6.78	32
NGL ($/bbl)	**49.92**	39.04	28
Total commodity revenue before hedging ($/boe)	**56.54**	43.13	31
Other revenue ($/boe)	**0.21**	0.19	11
Total revenue before hedging ($/boe)	**56.75**	43.32	31

Revenue

Revenue increased to $1.2 billion in 2005, an increase of 29 per cent compared to 2004 revenue of $902 million. Significantly higher commodity prices caused this higher revenue.

A breakdown of revenue is as follows:

Revenue

($ thousands)	2005	2004	% Change
Oil revenue	**519,272**	395,203	31
Natural gas revenue	**568,710**	442,537	29
NGL revenue	**72,973**	59,886	22
Total commodity revenue	**1,160,955**	897,626	29
Other revenue	**4,242**	4,156	2
Total revenue	**1,165,197**	901,782	29

Risk Management

The Trust's risk management activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board. The Risk Management Committee has the following mandate:

- protect unitholder return on investment;
- provide for minimum monthly cash distributions to unitholders;
- employ a portfolio approach to risk management by entering into a number of small positions that build upon each other;

- participate in commodity price upturns to the greatest extent possible while limiting exposure to price downturns; and,
- ensure profitability of specific oil and gas properties that are more sensitive to changes in market conditions.

The Trust realized cash hedging losses of $87.6 million for the year attributed primarily to capped contracts that expired on December 31, 2005. At the date of this MD&A the Trust had upside participation for 2006 on all produced volumes with the exception of those noted below, with downside price protection on 39 per cent of liquids production and 14 per cent of natural gas production (26 per cent of produced boes).

The Trust continues to execute a risk management strategy focused on put and put spread structures to manage commodity prices and continues to use fixed rate swaps to manage foreign exchange and interest rate exposures. The purchase of a put involves paying a premium to limit the exposure to downturns in commodity prices while participating in commodity price appreciation. At year end the Trust had bought puts with an average floor on oil production of US$52.68 per bbl and Cdn$8.16 per GJ on natural gas. The Trust also entered into sold put transactions that offset the cost of the bought put premiums. The $12.4 million cost of the put premiums has been incurred to protect a portion of 2006 revenue.

In addition to the above contracts, the Trust entered into long-term risk management structures to lock in returns on production acquired through the Redwater and NPCU acquisitions announced in December 2005. ARC has protected 5,000 barrels per day through 2009 with a three-way collar by partially financing the purchase of a US$55 floor with a sold US$40 put and US$90 call. ARC felt it prudent to sell the out-of-the-money put and call in order to reduce the cost of the US$55 floor and minimize its long-term premium commitments. As a result, ARC has US$55 price protection (down to US$40) on the acquired volumes costing an average of $1.9 million per year through 2009. If oil trades above US$90 in any one month, ARC will be limited to US$90 for that month, if WTI falls below US$40, ARC receives market price plus US$15 under the three-way collar. For a complete summary of the Trust's oil and natural gas hedges, please refer to "Hedging Program" under the "Investor Relations" section of the Trust's website at www.arcenergytrust.com.

The Trust considers its risk management contracts to be effective economic hedges as they meet the objectives of the Trust's risk management mandate. In order to mitigate credit risk, the Trust executes commodity and foreign currency hedging risk management with financially sound, credit worthy counterparties. All contracts require approval of the Trust's Risk Management Committee prior to execution. Deferred premiums payable will be recorded as a realized cash hedging loss when payment is made in a future period. These premiums may be partially offset if ARC sells any short-term options. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

Gain or Loss on Commodity and Foreign Currency Contracts

Gain or loss on commodity and foreign currency contracts comprise realized and unrealized gains or losses on commodity and foreign currency contracts that do not meet the accounting definition of the requirements of an effective hedge, even though the Trust considers all commodity and foreign currency contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate expense in the statement of income.

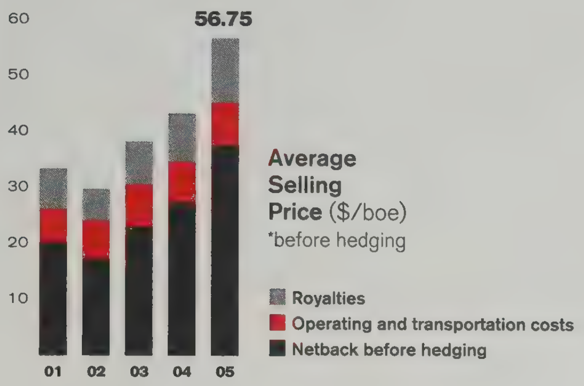
The Trust recorded a realized loss on commodity and foreign currency contracts of $87.6 million in 2005, which is virtually the same amount as realized in 2004.

The following is a summary of the gain (loss) on commodity and foreign currency contracts for 2005:

Commodity and foreign currency contracts

($ thousands)	**Crude Oil & Liquids**	**Natural Gas**	**Foreign Currency**	**2005 Total**	2004 Total
Realized cash (loss) gain on contracts (1)	**(75,816)**	**(12,491)**	**749**	**(87,558)**	(86,909)
Non-cash gain on contracts	**-**	**-**	**-**	**-**	4,883
Non-cash amortization of opening deferred hedge loss	**-**	**-**	**-**	**-**	(14,575)
Unrealized (loss) gain on contracts, change in fair value (2)	**16,465**	**(17,531)**	**1,066**	**-**	10,533
Total gain (loss) on commodity and foreign currency contracts	**(59,351)**	**(30,022)**	**1,815**	**(87,558)**	(86,068)

(1) Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.
(2) The unrealized (loss) gain on contracts represents the change in fair value of the contracts during the period.



Operating Netbacks

The Trust's operating netback, prior to realized hedging losses, increased 37 per cent to $37.66 per boe in 2005 compared to $27.39 per boe in 2004. The increase in netbacks in 2005 is due to higher commodity prices.

The netback was reduced by realized losses on commodity and foreign currency contracts of $4.26 per boe for 2005, very similar to losses of $3.94 per boe in 2004.

The components of operating netbacks are shown below:

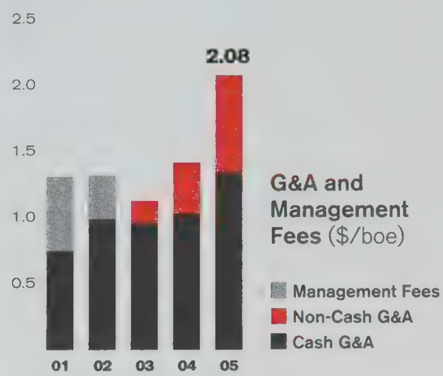
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**2005 Total** ($/boe)	2004 Total ($/boe)
Weighted average sales price	61.11	8.96	49.91	**56.54**	43.13
Other revenue	–	–	–	**0.21**	0.19
Total revenue	61.11	8.96	49.91	**56.75**	43.32
Royalties	(11.58)	(1.85)	(13.18)	**(11.46)**	(8.51)
Transportation	(0.13)	(0.21)	–	**(0.70)**	(0.71)
Operating costs (1)	(8.62)	(0.98)	(4.69)	**(6.93)**	(6.71)
Netback prior to hedging	40.78	5.92	32.04	**37.66**	27.39
Realized loss on commodity and foreign currency contracts	(8.83)	(0.20)	–	**(4.26)**	(3.94)
Netback after hedging	31.95	5.72	32.04	**33.40**	23.45

(1) Operating expenses are composed of direct costs incurred to operate oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

Royalties increased to $11.46 per boe in 2005 compared to $8.51 per boe in 2004, up 35 per cent as a result of higher commodity prices. Royalties are calculated and paid based on commodity revenue net of associated transportation costs and before any commodity hedging gains or losses. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs remained unchanged at approximately 20 per cent.

Operating costs, net of processing income, remained relatively consistent at $142.2 million in 2005 compared to $139.7 million in 2004. Operating costs per boe increased three per cent to $6.93 per boe in 2005 compared to $6.71 per boe in 2004. The higher costs of services throughout the industry, particularly for service rigs, trucking costs and mechanical services, has caused the increase in operating costs.

In 2006 it is expected that base operating costs (before Redwater and NPCU) will increase over 10 per cent to $7.70 per boe. With the addition of the higher cost Redwater and NPCU properties it is estimated that average operating costs will increase to $8.65 per boe in 2006.



General and Administrative Expenses and Trust Unit Incentive Compensation

Cash general and administrative expenses ("G&A"), net of overhead recoveries on operated properties, increased to $27.4 million ($1.34 per boe) in 2005 from $21.4 million ($1.03 per boe) in 2004. Increases in cash G&A expenses in total and per boe were the result of the increasing costs to manage the business associated with increased staff levels and increased compensation. Due to unprecedented levels of activity for ARC and for the industry as a whole in 2005, the costs associated with hiring, compensating and retaining employees and consultants has risen. It is essential for the Trust to maintain competitive compensation levels to ensure that we continue to attract and retain the most qualified individuals.

The following is a breakdown of G&A and trust unit incentive compensation expense:

G&A and Trust Unit Incentive Compensation Expense

($ thousands except per boe)	2005	2004	% Change
G&A expenses	**35,044**	30,733	14
Whole Unit Plan compensation expense (1)	**1,062**	–	100
Operating recoveries	**(8,659)**	(9,307)	(7)
Cash G&A expenses	**27,447**	21,426	28
Accrued compensation - Rights Plan	**6,525**	5,171	26
Accrued compensation - Whole Unit Plan	**8,774**	2,915	201
Total G&A and trust unit incentive compensation expense	**42,746**	29,512	45
Cash G&A expenses per boe	**1.34**	1.03	30
Total G&A and trust unit incentive compensation expense per boe	**2.08**	1.42	46

(1) Plan started in 2004 with the first cash payment made in April 2005.

A non-cash trust unit incentive compensation expense ("non-cash compensation expense") of $15.3 million ($0.74 per boe) was recorded in 2005 compared to $8.1 million ($0.39 per boe) in 2004. This non-cash amount relates to estimated costs of the Trust Unit Incentive Rights Plan ("Rights Plan") and the Whole Trust Unit Incentive Plan to December 31, 2005 and reflects the strong market performance of ARC's units during the year.

Rights Plan

The Rights Plan provided employees, officers and independent directors the right to purchase units at a specified price. In general, the rights had a five year term and vested equally over three years. The exercise price of the rights is adjusted downwards from time to time by the amount that distributions to unitholders, in any calendar quarter exceeds 2.5 per cent of the Trust's net book value of property, plant and equipment. The rights plan was replaced by a Whole Unit Plan during 2004 after which no further rights under the rights plan were issued. The number of rights outstanding declined by 1.7 million in the year from exercises or cancellations, to end the year at 1.3 million outstanding.

For the year ended December 31, 2005, the compensation expense for the rights plan based on the fair value calculation resulted in an expense of $6.5 million compared to $5.2 million in 2004.

Whole Trust Unit Incentive Plan ("Whole Unit Plan")

In March 2004, the Board of Directors approved a new Whole Unit Plan to replace the Rights Plan for new awards granted subsequent to the first quarter of 2004. The new Whole Unit Plan results in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of units is variable and will vest at the end of three years.

Upon vesting, the plan participant is entitled to receive a cash payment based on the fair value of the underlying trust units plus accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the performance of the Trust compared to its peers. The PTU grant is adjusted by a performance multiplier. The performance multiplier is based on the percentile rank of the Trust's total unitholder return, which is the sum of the increase in market price of the units over the period plus the amount of distributions over the period, compared to its peers. The performance multiplier can range from zero to two.

The value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period with the expense amount being determined by the unit price, the number of PTUs to be issued on vesting, and distributions. Therefore, the expense recorded in the statement of income fluctuates over time.

The following table shows the changes during the year of RTUs and PTUs outstanding:

(in thousands of units)	number of RTUs	number of PTUs
Balance, beginning of year	225	128
Vested	(79)	–
Granted	367	305
Forfeited	(34)	(42)
Balance, end of year	479	391

Under the Whole Unit Plan $13.6 million was paid or accrued during the year versus $2.9 million in 2004. The large increase in the accrued value of the RTUs and PTUs outstanding is attributed to the considerable increase in the Trust's unit value in the market, and the increase in the performance multiplier on the PTUs to two reflecting ARC's top quartile returns compared to other midsized oil and gas producers.

The Trust expects 2006 G&A costs, excluding non-cash G&A associated with the Trust's Rights Plan and Whole Unit Plan, to be approximately $1.70 per boe. In addition, the Trust expects 2006 non-cash G&A of approximately $0.65 per boe for the non-cash trust unit incentive compensation expense associated with the Rights Plan and Whole Unit Plan. The increasing G&A costs in 2006 are the result of higher compensation levels associated with hiring and retaining qualified employees and consultants in a competitive environment.

Interest Expense

Interest expense increased to $16.9 million in 2005 from $13.3 million in 2004. The increase is attributed to increased interest rates and to a higher average debt balance in 2005 compared to 2004 as a result of acquisitions funded by debt. Also during the year the Trust paid out an 8.05 per cent, US$21 million note and refinanced it at a lower interest rate. The amount paid to settle the note early was Cdn$1.3 million and was included as interest expense.

The following is a summary of the debt balance and interest expense:

Interest Expense

($ thousands)	**2005**	2004	% Change
Year end debt balance (1)	**526,636**	220,549	139
Fixed rate debt	**268,156**	220,259	
Floating rate debt	**258,480**	290	
Interest expense before interest rate swaps (2)	**17,420**	14,675	19
Gain on interest rate hedge	**(474)**	(1,355)	
Net interest expense	**16,946**	13,320	27

(1) Includes both long-term and current portions of debt.

(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

Foreign Exchange Gains and Losses

The Trust recorded a gain of $6.4 million ($0.31 per boe) on foreign exchange transactions compared to a gain of $20.7 million ($1.00 per boe) in 2004. These amounts include both realized and unrealized foreign exchange gains and losses. Unrealized foreign exchange gains and losses are due to revaluation of US denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain/loss impacts net income but does not impact cash flow as it is a non-cash amount. Realized foreign exchange gains or losses arise from US denominated transactions such as interest payments, debt repayments and hedging settlements.

Taxes

Capital taxes paid or payable by ARC, based on debt and equity levels at the end of the year, amounted to $3.9 million in 2005 compared to $2.8 million in 2004. The increase in 2005 capital taxes was attributed to the higher taxable capital base as a result of asset acquisitions, partially offset by a decrease in the capital tax rate, as well as a $0.9 million reassessment on prior years tax return filings by Star Oil & Gas Ltd. ("Star"), which ARC purchased in 2003.

Corporate acquisitions completed in 2005 resulted in the Trust recording a future income tax liability of $213.8 million due to the difference between the tax basis and the fair value assigned to the acquired assets. The amount of tax pools versus asset value is one of the parameters that impacts the Trust's acquisition bid levels.

In the Trust's structure, payments are made between ARC Resources Ltd. ("ARL"), the operating subsidiary of the Trust, and the Trust, transferring both income and future tax liability to the unitholders. At the current time, ARC does not anticipate any cash taxes will be paid by ARL.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to $12.88 per boe in 2005 from $11.51 per boe in 2004. The higher DD&A rate is due to the Redwater and NPCU property acquisition in the fourth quarter of 2005 for which the Trust recorded a higher proportionate cost per barrel of proved reserves of the acquired properties compared to the existing ARC properties. In addition, the higher asset retirement obligation recorded in 2005 has resulted in higher accretion expense in 2005.

A breakdown of the DD&A rate is a follows:

DD&A Rate

($ thousands except per boe amounts)	2005	2004	% Change
Depletion of oil & gas assets (1)	**259,308**	235,094	10
Accretion of asset retirement obligation (2)	**5,207**	4,580	14
Total DD&A	**264,515**	239,674	10
DD&A rate per boe	**12.88**	11.51	12

(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment ("PP&E") balance and is being depleted over the life of the reserves.
(2) Represents the accretion expense on the asset retirement obligation during the year.

The costs subject to depletion included $61.9 million relating to the capitalized portion of the asset retirement obligation as at December 31, 2005 ($42.3 million as at December 31, 2004), net of accumulated depletion.

Goodwill

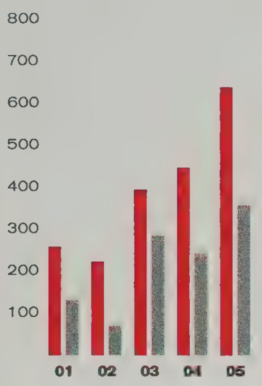
The goodwill balance of $157.6 million arose as a result of the acquisition of Star in 2003. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets for accounting purposes acquired in the transaction.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2005.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $268.8 million in 2005 compared to $193.8 million in 2004. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base. The significant increase in 2005 capital expenditures is due to the costs of the capital development program needed to replace production in the year.

During the year, the Trust drilled 250 gross wells (220 net wells) on operated properties; consisting of 68 gross oil wells and 180 gross natural gas wells most of which were shallow gas wells, and two dry holes for a total success rate of 99 per cent in 2005. In addition, the Trust participated in 402 gross wells drilled by other operators.



Cash Flow and Earnings ($ millions)

In addition to capital expenditures on development activities, the Trust completed net property acquisitions of $91.3 million in 2005. Major property acquisitions were in the following areas: Berrymoor and Buck Creek in Alberta and Weirhill and Steelman in Saskatchewan.

The Trust also completed a number of corporate acquisitions including Romulus Exploration Inc. in June 2005 for total consideration of $42 million and companies holding the Redwater and NPCU properties in December 2005 for total consideration of $463 million.

Capital expenditures on development activities and acquisitions resulted in an increase in proved plus probable oil and gas reserves from 244 mmboe at year end 2004 to 287 mmboe at year end 2005.

Approximately 95 per cent of the $269 million capital program was financed from cash flow from operations in 2005 versus 57 per cent in 2004. Property and corporate acquisitions were financed through a combination of debt and equity.

A breakdown of capital expenditures and net acquisitions is shown below:

Capital Expenditures

($ thousands)	**2005**	2004	% Change
Geological and geophysical	**9,219**	5,388	71
Drilling and completions	**200,873**	144,487	39
Plant and facilities	**55,032**	41,089	34
Other capital	**3,710**	2,820	32
Total capital expenditures	**268,834**	193,784	39
Producing property acquisitions (1)	**111,324**	(529)	
Producing property dispositions (1)	**(20,038)**	(57,691)	
Corporate acquisitions (2)	**504,996**	72,009	
Total capital expenditures and net acquisitions	**865,116**	207,573	318
Total capital expenditures and net acquisitions financed with cash flow	**256,104**	110,846	
Total capital expenditures and net acquisitions financed with debt	**609,012**	96,727	

(1) Value is net of post-closing adjustments.
(2) Represents total consideration for the transactions, including fees but is prior to the related future income tax liability, asset retirement obligation and working capital assumed on acquisition.

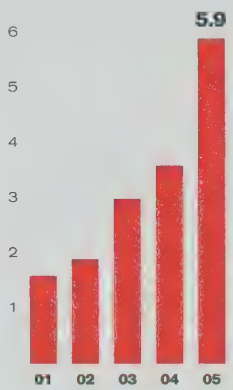
ARC expects to undertake significant development activities again in 2006 resulting in a $340 million capital budget. New activities include spending $25 million on a commercial scale Natural Gas from Coal ("NGC") project and incurring a $17 million increase in capital allocated to moderate risk exploration.

Asset Retirement Obligation and Reclamation Fund

At December 31, 2005, the Trust has recorded an Asset Retirement Obligation ("ARO") of $165.1 million ($73 million at December 31, 2004) for future abandonment and reclamation of the Trust's properties. The ARO increased by $76.2 million during 2005 as a result of additional liabilities associated with the acquisitions of Redwater and NPCU, and the wells drilled in 2005. Also the ARO increased because the inflation factor used to calculate the future retirement obligation was increased from

1.5 per cent to two per cent in 2005. The ARO further increased by $5.2 million for accretion expense in 2005 ($4.6 million in 2004) and was reduced by $4.9 million ($3.2 million in 2004) for actual abandonment expenditures incurred in 2005. The Trust did not record a gain or loss on actual abandonment expenditures incurred as the costs closely approximated the liability value included in the ARO.

ARC contributed $6 million cash to its reclamation fund in 2005 ($6 million in 2004) and earned interest of $0.8 million ($1.2 million in 2004) on the fund balance. The fund balance was reduced by $4.6 million for cash-funded abandonment expenditures in 2005 ($3.1 million in 2004). This fund, invested in money market instruments, is established to provide for future abandonment and reclamation liabilities. Future contributions are currently set at approximately $6 million per year over 20 years in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred over the next 61 years. In addition, as a result of the Redwater/NPCU acquisition the Trust has committed to additional yearly contributions starting at $6.1 million per year (resulting in a total 2006 contribution of $12.1 million). Currently, the fund balance stands at $23.5 million.



Total Capitalization ($ billions)

Capital Structure

A breakdown of the Trust's capital structure is as follows:

Capitalization, Financial Resources and Liquidity

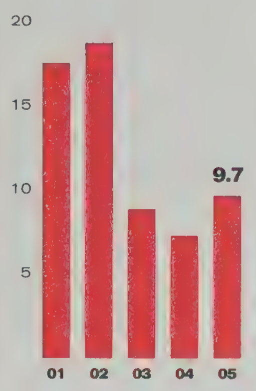
($ thousands except per unit and per cent amounts)	**2005**	2004
Revolving credit facilities	**258,480**	290
Senior secured notes	**268,156**	220,259
Working capital deficit excluding short-term debt (1)	**51,450**	44,293
Net debt obligations	**578,086**	264,842
Units outstanding and issuable for exchangeable shares (thousands)	**202,039**	188,804
Market price per unit at end of year	**26.49**	17.90
Market value of units and exchangeable shares	**5,352,013**	3,379,592
Total capitalization (2)	**5,930,099**	3,644,434
Net debt as a percentage of total capitalization	**9.7%**	7.3%
Net debt obligations	**578,086**	264,842
Cash flow from operations	**639,511**	448,033
Net debt to cash flow	**0.9**	0.6

(1) The working capital deficit excludes the balances for commodity and foreign currency contracts.

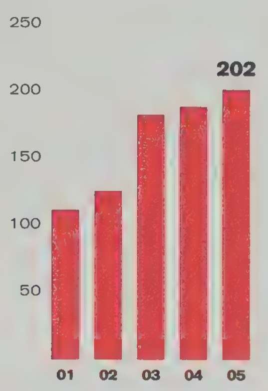
(2) Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

On December 15, 2005 the Trust repaid the remaining US$21 million outstanding on its 8.05 per cent senior secured notes originally issued in November 2000 pursuant to an Uncommitted Master Shelf Agreement. The Trust paid US$1.1 million in order to retire this note based upon the discounted value of interest payable at the 8.05 per cent rate and current market interest rates. Concurrent with the repayment, US$75 million of senior secured notes were issued under an Amended Uncommitted Master Shelf Agreement. This note pays a quarterly coupon of 5.42 per cent per annum and requires equal principal payments of US$9,375,000 over an eight year period commencing in 2010.

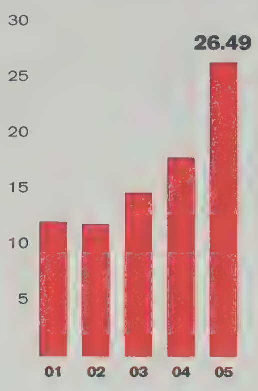
In conjunction with the December acquisition of Redwater and the NPCU, the Trust increased its syndicated credit facility to $700 million and its working capital facility to $25 million resulting in a total borrowing base of $950 million. The increase in the borrowing base did not impact any key terms in the credit facility such as security or covenants. The next annual credit review will occur during the first quarter of 2006 at which time the Trust will reduce its available credit facilities to reduce fees on credit facilities it does not expect to utilize in the near future.



Net Debt as a Percentage of Total Capitalization (%)



Units Outstanding at Year End (millions)
(includes units issuable for exchangeable shares)



Unit Market Price ($/unit at December 31)

The Trust intends to finance its $340 million 2006 capital program with cash flow and the proceeds of the distribution reinvestment program with any remainder being financed with debt.

Unitholders' Equity

At December 31, 2005, there were 199.1 million trust units issued and 2.9 million units issuable for exchangeable shares, a seven per cent increase from the 185.8 million units issued and three million units issuable for exchangeable shares at December 31, 2004.

The increase in the number of units outstanding is attributable to the following:

	Average Price (per unit)	Proceeds ($ millions)	# of Units (millions)
Units Issued at December 31, 2004	–	–	185.8
December 2005 equity offering	$ 26.65	239.9	9.0
Units issued from treasury pursuant to DRIP program	$ 19.92	48.8	2.5
Units issued on exercise of employee rights	$ 16.03	24.1	1.5
Units issued pursuant to exchange of ARL exchangeable shares	$ 11.04	4.0	0.3
Units issued at December 31, 2005			**199.1**

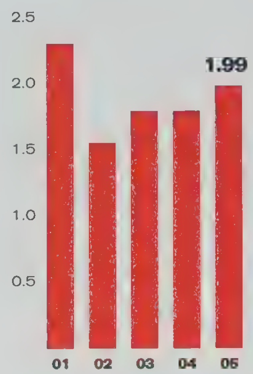
The Trust issued nine million units at $26.65 in December 2005 for proceeds of $239.9 million less underwriter's fees of $12 million for net proceeds of $227.9 million. Proceeds from the offering were used to partially repay debt associated with the Redwater and NPCU acquisitions.

The Trust made its final issuance of rights under the Rights Plan during 2004. There will be no future issuances of rights as the rights plan was replaced with a new Whole Unit Plan in 2004. The existing rights plan will be in place until the remaining 1.3 million rights outstanding as of December 31, 2005 are exercised or cancelled. These rights have an adjusted exercise price of $10.22 and have an average remaining contractual life of 3.3 years and expire at various dates to March 22, 2009. Of the rights outstanding at December 31, 2005, a total of 0.6 million were exercisable at that time.

The Whole Unit Plan introduced in 2004 is a cash compensation plan for employees, officers and directors of the Trust and does not involve any units being issued from treasury. The Trust has made provisions whereby employees may elect to have units purchased for them on the market with the cash received upon vesting.

Cash Distributions

ARC declared cash distributions of $377 million ($1.99 per unit), representing 59 per cent of 2005 cash flow from operations compared to cash distributions of $330 million ($1.80 per unit), representing 74 per cent of cash flow from operations in 2004. The remaining 41 per cent of 2005 cash flow ($263 million) was used to fund 95 per cent of ARC's 2005 capital expenditures and make contributions, including interest, to the reclamation fund ($6.8 million). The actual amount of cash flow withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is at the discretion of the Board of Directors.



Cash Distributions ($/unit)

Cash flow and cash distributions in total and per unit were as follows:

Cash flow and distributions

	($ millions)			($ per unit)		
	2005	2004	% Change	**2005**	2004	% Change
Cash flow from operations	**639.5**	448.0	43	**3.35**	2.41	39
Reclamation fund contributions (1)	**(6.8)**	(7.2)	(6)	**(0.04)**	(0.04)	–
Capital expenditures funded with cash flow	**(256.1)**	(110.8)	131	**(1.34)**	(0.60)	123
Other (2)	**–**	–	–	**0.02**	0.03	(33)
Cash distributions	**376.6**	330.0	14	**1.99**	1.80	11

(1) Includes interest income earned on the reclamation fund balance that is retained in the reclamation fund.
(2) Other represents the difference due to cash distributions paid being based on actual units at each distribution date whereas per unit cash flow, reclamation fund contributions and capital expenditures funded with cash flow are based on weighted average trust units in the year plus units issuable for exchangeable shares at year end.

Monthly cash distributions for the first quarter of 2006 have been set at $0.20 per unit subject to monthly review based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

Historical Cash Distributions by Calendar Year

The following table presents cash distributions paid in each calendar period.

Calendar Year	Distributions (1)	Taxable Portion	Return of Capital
2006 YTD (2)	0.40	0.39 (2)	0.01 (2)
2005	1.94	1.90 (3)	0.04 (3)
2004	1.80	1.69	0.11
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	–	0.81
Cumulative	**$ 16.43**	**$ 9.73**	**$ 6.70**

(1) Based on cash distributions paid in the calendar year.
(2) Based on cash distributions paid in 2006 up to and including February 15, 2006 and estimated taxable portion of 2006 distributions of 98 per cent.
(3) Based on taxable portion of 2005 distributions of 98 per cent.

2005 Monthly Cash Distributions

Actual cash distributions paid along with relevant payment dates are as follows:

Ex-Distribution Date	Record Date	Distribution Payment Date	Total Distribution	Taxable Portion	Return of Capital
December 29, 2004	December 31, 2004	January 17, 2005	0.15	0.1470	0.0030
January 27, 2005	January 31, 2005	February 15, 2005	0.15	0.1470	0.0030
February 24, 2005	February 28, 2005	March 15, 2005	0.15	0.1470	0.0030
March 29, 2005	March 31, 2005	April 15, 2005	0.15	0.1470	0.0030
April 27, 2005	April 30, 2005	May 16, 2005	0.15	0.1470	0.0030
May 27, 2005	May 31, 2005	June 15, 2005	0.15	0.1470	0.0030
June 28, 2005	June 30, 2005	July 15, 2005	0.15	0.1470	0.0030
July 27, 2005	July 31, 2005	August 15, 2005	0.15	0.1470	0.0030
August 28, 2005	August 31, 2005	September 15, 2005	0.17	0.1666	0.0034
September 28, 2005	September 30, 2005	October 17, 2005	0.17	0.1666	0.0034
October 27, 2005	October 31, 2005	November 15, 2005	0.20	0.1960	0.0040
November 28, 2005	November 30, 2005	December 15, 2005	0.20	0.1960	0.0040
Total 2005			**1.94**	**1.9012**	**0.0388**

Taxation of Cash Distributions

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the units held. For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

For 2005, cash distributions paid in the calendar year will be 98 per cent return on capital (taxable) and two per cent return of capital (tax deferred). The increase in the taxable portion of distributions to 98 per cent is the result of increasing commodity prices and in turn increasing cash flow of the Trust.

The exchangeable shares of ARL, a corporate subsidiary of the Trust, may provide a more tax-effective basis for investment in the Trust. The ARL exchangeable shares are traded on the TSX under the symbol "ARX" and are convertible into units, at the option of the shareholder, based on the then current exchange ratio. Exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month's unit distribution multiplied by the then current exchange ratio and divided by the 10 day weighted average trading price of the units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is taxed, in most circumstances, as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a unit.

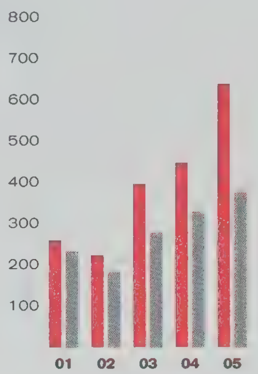
Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature as disclosed in the following table.

	Payments Due By Period				
($ millions)	2006	2007-2008	2009-2010	Thereafter	Total
Debt repayments	–	279.4	49.2	198.0	526.6
Reclamation fund contributions (1)	6.1	11.8	10.2	80.9	109.0
Purchase commitments	2.4	3.4	3.2	8.0	17.0
Operating leases	4.1	8.1	7.3	–	19.5
Derivative contract premiums (2)	12.4	–	–	–	12.4
Retention bonuses	1.0	1.0	–	–	2.0
Total contractual obligations	**26.0**	**303.7**	**69.9**	**286.9**	**686.5**

(1) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition.
(2) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At any given point in time, it is estimated that the Trust has committed to approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. This commitment has not been disclosed in the above referenced commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.



The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations.

Off Balance Sheet Arrangements

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2005. The total obligation for future lease payments under all operating leases is disclosed in the "Commitments and Contingencies" section of this MD&A.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of approximately $12.4 million will be paid in 2006 for the put contracts in place at year end. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2005 on the balance sheet. The total obligation for future premium payments is disclosed in the "Commitments and Contingencies" section of this MD&A.

Financial Reporting Update

The following new standard has been reviewed by the Trust during 2005:

Financial Instruments – Recognition and Measurement – On January 27, 2005, the Accounting Standard's Board ("AcSB") issued CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", CICA Handbook section 1530 "Comprehensive Income" and CICA Handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and international accounting standards. The new standards are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

Critical Accounting Estimates

The Trust has continuously evolved and documented its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated.

The Trust's financial and operating results incorporate certain estimates including:

(a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;

(b) estimated capital expenditures on projects that are in progress;

(c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;

(d) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;

(e) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and

(f) estimated future recoverable value of property, plant and equipment and goodwill.

The Trust has hired individuals and consultants who have the skills required to make such estimates and ensures individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

The ARC leadership team's mandate includes ongoing development of procedures, standards and systems to allow ARC staff to make the best decisions possible and ensuring those decisions are in compliance with the Trust's environmental, health and safety policies.

Financial Reporting and Internal Controls Update

On July 31, 2002, the United States Congress enacted the Sarbanes Oxley Act ("SOX"). SOX applies to all companies registered with the Securities and Exchange Commission ("SEC"). Although ARC is not listed on a US stock exchange, the Trust is registered with the SEC as a result of having acquired Startech Energy Inc. in 2001 and therefore is required to comply with certain portions of the SOX legislation. There are various components to the SOX legislation, however the most comprehensive is Section 404 "Internal Controls Over Financial Reporting". Section 404 requires that management undertake the following:

- identify and document internal controls that impact financial reporting;
- assess the effectiveness of those internal controls;
- remediate any deficiencies in internal controls and/or implement any required controls that are not already in place;
- test the internal controls to ensure that they are operating effectively; and
- issue a report, to be signed by the CEO and CFO, on management's assessment of the effectiveness of internal controls and communicate any material weaknesses.

ARC is currently required to comply with section 404 of the SOX legislation on December 31, 2006. In conjunction with the 2006 year end audit, ARC's external auditors will audit the Trust's internal controls and will issue two opinions, one on the auditor's assessment of the effectiveness of internal controls over financial reporting and one on the auditor's opinion on management's assessment of the internal controls over financial reporting.

The Trust currently has a comprehensive plan and a dedicated team of individuals in place to execute the plan of meeting the SOX Section 404 compliance date.

As of December 31, 2005, an internal evaluation was carried out of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934. Based on that evaluation, the President and Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective to ensure that material information relating to the Trust is made known to management on a timely basis and is included in this report. No changes were made to our internal control over financial reporting during the year ended December 31, 2005, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In addition to SOX, ARC is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). ARC is currently complying with this legislation by filing bare interim and annual certificates. It is expected that ARC will be required to file a full annual certificate in conjunction with the December 31, 2006 year end. The Canadian requirements closely parallel the SEC's certification rules, however, currently there is no requirement to have external auditor's opinion on the Trust's internal controls or management's assessment thereof.

Objectives and 2006 Outlook

It is the Trust's objective to provide superior long-term returns to unitholders by focusing on the key strategic objectives of the business plan. The Trust has provided unitholders with the following one, three and five year returns (assuming the reinvestment of distributions):

Total Returns

($ per unit except for per cent)	One year	Three year	Five year
Distributions per unit	$ 1.99	$ 5.59	$ 9.46
Capital appreciation per unit	8.59	14.59	15.19
Total return per unit	$ 10.58	$ 20.18	$ 24.65
Annualized total return per unit	62.4%	46.5%	38.8%

To the end of 2005, the Trust has provided cumulative cash distributions of $16.23 per unit and capital appreciation of $16.49 per unit for a total return of $32.72 per unit (27.9 per cent annualized total return) for unitholders who invested in the Trust at inception in 1996.

The key future objectives of the Trust's business plan, as identified below, are reviewed annually by the Board. The Trust was successful in meeting all of its objectives in 2005 as individually addressed below. They continue to be key objectives for 2006.

- **Annual reserves replacement** – The Trust increased its proved plus probable reserves from 244 mmboe at year end 2004 to 287 mmboe at year end 2005 through a combination of the reserves additions associated with the Trust's $269 million 2005 capital budget and reserves purchased in corporate and property acquisitions (net of dispositions) for $598 million.

- **Ensuring acquisitions are strategic and enhance unitholder returns** – The Trust added significant assets in its core Pembina and southeast Saskatchewan areas in 2005. In addition, the Trust added another long-life, light oil property to its portfolio with the acquisition of a controlling interest in the Redwater field. ARC believes that long-life, light oil properties will provide future opportunities to enhance unitholder value through the application of tertiary recovery methods.

- **Controlling costs** – Due to the diligence of field and office operating staff, the Trust's operating costs per boe in 2005 increased less than three per cent over 2004 costs. Cash G&A costs in 2005 increased 30 per cent to $1.34 per boe from $1.03 per boe in 2004 as a result of both increased staff count and increased compensation costs due to the extremely competitive marketplace for experienced staff with oil and gas expertise. The Trust believes the $1.34 per boe cash G&A costs will be "middle of the pack" for mid-sized oil and gas producers, representing an appropriate balance of the Trust's objective to develop and retain the best staff in the industry, discussed below, and the desire to keep costs as low as possible. The Trust's three year average FD&A costs of $11 per boe prior to incorporating future development costs "FDC" and $13.50 per boe with FDC, ARC believes will be better than the industry average and demonstrates ARC's effective use of retained cash.

- **Conservative utilization of debt** – The Trust's debt levels were under 10 per cent of total capitalization and debt to 2005 cash flow was 0.7 times for the year ended 2005 taking into account full year cash flow on properties acquired later in the year.

- **Continuously developing the expertise of our staff and seeking to hire and retain the best in the industry** – the Trust runs an active training and development program for its employees and encourages personal development. The Trust continues to assess compensation levels in the industry to ensure that the Trust's compensation is competitive so as to attract and retain the best employees. The Trust's long-term incentive plan's payouts are directly tied to the Trust's performance providing alignment between employees and investors. Since ARC's 62 per cent total return in 2005 was one of the top returns in our sector, total non-cash long-term compensation expense increased to $0.74 per boe in 2005.

- **Building relationships and conducting business in a way that is viewed as fair and equitable** – ARC employees, leadership team and directors work hard to build the ARC "franchise value" through honest, transparent dealings with our business partners. "Treating all people with respect" is a key message inside and outside the organization. This basic business fundamental allows us to build enduring relationships with joint venture partners, land owners, investors, banks and lending institutions, governments and the investment community.

- **Promoting the use of proven and effective technologies** – The Trust continues to research new technologies in an effort to conduct its operations in the most efficient and cost effective manner. With the Trust's purchase of Redwater and additional interest in Pembina, the Trust will be increasing its research into tertiary recovery methods.

- **Being an industry leader in health, safety and environmental performance** – The Trust's primary focus continues to be on operating in a safe, reliable and responsible fashion. The Trust is committed to the platinum level of CAPP Stewardship reporting and continues to achieve reductions in greenhouse gas emissions under the Canada Climate Change VCR initiative.

- **Continuing to actively support local initiatives in the communities in which we live and work** – The Trust is very actively involved in charitable and philanthropic causes both in Calgary and in the rural communities in which it operates. ARC continued to be a strong supporter of the United Way, Alberta Cancer Foundation, Alberta Children's Hospital and many community organizations in rural centres.

Following is a summary of the Trust's 2006 Guidance issued by way of news release on December 6, 2005:

	2005 Revised Guidance	Actual 2005	% Change	**2006 Guidance**
Production (boe/d)	56,000	56,254	–	**61,000**
Expenses ($/boe):				
Operating costs	7.00	6.93	(1)	**8.65**
Transportation	0.70	0.70	–	**0.70**
G&A expenses – cash	1.25	1.34	7	**1.70**
G&A expenses – stock compensation plans	0.60	0.74	23	**0.65**
Interest	0.75	0.83	11	**1.40**
Taxes	0.15	0.19	–	**0.15**
Capital expenditures ($ millions)	270	269	–	**340**
Weighted average trust units and units issuable (millions)	191.3	191.2	–	**205.5**

Actual 2005 results were in line with 2005 guidance except for G&A expenses, which were higher because of increased staff compensation costs and expected payments under the Long-term Employee Incentive Plan. Interest costs increased because of acquisitions, which were made during the year and partially funded by debt.

2006 Cash Flow and Hedging Sensitivity

Below is a table that illustrates sensitivities to pre-hedged cash flow with operational changes and changes to the business environment:

		Impact on Annual Cash Flow	
Business environment	Assumption	Change	$/Unit
Oil price (US$WTI/bbl) (1)	$ 55.00	$ 1.00	$ 0.05
Natural gas price (Cdn$AECO/mcf) (1)	$ 10.55	$ 0.10	$ 0.03
CAD/USD exchange rate	$ 0.87	$ 0.01	$ 0.06
Interest rate on debt	4.1%	1.0%	$ 0.03
Operational			
Liquids production volume (bbl/d)	31,000	1.0%	$ 0.02
Gas production volumes (mmcf/d)	181.0	1.0%	$ 0.02
Operating expenses per boe	$ 8.60	1.0%	$ 0.01
Cash G&A expenses per boe	$ 1.70	10.0%	$ 0.02

(1) Analysis does not include the effect of derivative contracts.

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with the Trust's business that can impact the financial results as follows:

VOLATILITY OF OIL AND NATURAL GAS PRICES

The Trust's operational results and financial condition, and therefore the amount of distributions paid to the unitholders will be dependent on the prices received for oil and natural gas production. Oil and gas prices have fluctuated widely during recent years and are determined by economic and in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Trust's financial condition and therefore on the distributions to the holders of trust units. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivative contracts. If ARC engages in activities to manage its commodity price exposure, the Trust may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity derivative contracts activities could expose ARC to losses. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

VARIATIONS IN INTEREST RATES AND FOREIGN EXCHANGE RATES

Variations in interest rates could result in a significant increase in the amount the Trust pays to service debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Trust's net production revenue. In addition, the exchange rate for the Canadian

dollar versus the US dollar has increased significantly over the last 12 months, resulting in the receipt by the Trust of fewer Canadian dollars for its production, which may affect future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/US exchange rates may impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

RESERVES ESTIMATES

The reserves and recovery information contained in ARC's independent reserves evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserves evaluator. The reserves report was prepared using certain commodity price assumptions that are described in the notes to the reserves tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Trust and substituted for the price assumptions utilized in those reserves reports, the present value of estimated future net cash flows for the Trust's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions.

DEPLETION OF RESERVES AND MAINTENANCE OF DISTRIBUTION

ARC's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on ARC's success in exploiting its reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, the Trust's reserves and production will decline over time as the oil and natural gas reserves are produced out.

There can be no assurance that the Trust will make sufficient capital expenditures to maintain production at current levels; nor as a consequence, that the amount of distributions by the Trust to unitholders can be maintained at current levels.

To the extent that external sources of capital, including the issuance of additional trust units become limited or unavailable, ARC's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves could be impaired. To the extent that ARC is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributions could be reduced.

There can be no assurance that ARC will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

ACQUISITIONS

The price paid for reserves acquisitions is based on engineering and economic estimates of the reserves made by independent engineers modified to reflect the technical views of management. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil, natural gas, natural gas liquids and sulphur, future prices of oil, natural gas, natural gas liquids and sulphur and operating costs, future capital expenditures and royalties and other government levies that will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust. In particular, changes in the prices of and markets for oil, natural gas, natural gas liquids and sulphur from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the units. In addition, all such estimates involve a measure of geological and engineering uncertainty that could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flows and distributions to unitholders.

OPERATIONAL AND RESERVE RISKS RELATING TO THE ACQUISITION OF ASSETS

Risk factors set forth in this MD&A relating to the oil and natural gas business and the operations and reserves of the Trust apply equally in respect of the acquisitions that the Trust makes over time. Reserve and recovery information contained in this MD&A in respect of acquisitions is only an estimate and the actual production from and ultimate reserves of the acquisitions, particularly the NPCU and Redwater properties may be greater or less than the estimates contained in such reports. There are significant environmental reclamation liabilities attributable to the NPCU and Redwater properties.

COMPETITION

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts in the oil and gas industry that are competing for the acquisition of properties with longer life reserves and properties with exploitation and development opportunities. As a result of such increasing competition, it will be more difficult to acquire reserves on beneficial terms. ARC competes for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than the Trust.

NATURE OF UNITS

Units will have no value when the oil and gas reserves from the properties can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both a return of capital and a return on investment.

The units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. The units represent a fractional interest in the Trust. As holders of units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation. The Trust's sole assets will be the royalty interests

in the properties. The price per unit is a function of anticipated distributable income, the properties acquired by ARC and ARC's ability to effect long-term growth in the value of the Trust. The market price of the units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the units.

The net asset value, utilizing assumptions by independent engineers, of the assets of the Trust will vary from time to time dependent upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the units from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may be greater than the net asset value of the Trust's assets.

ENVIRONMENTAL CONCERNS

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of ARC or its working interests. Such legislation may be changed to impose higher standards and potentially more costly obligations on ARC. Although ARC has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy its actual future environmental and reclamation obligations. Additionally, the potential impact on the Trust's operations and business of the December 1997 Kyoto Protocol, which has been ratified by Canada, with respect to instituting reductions of greenhouse gases, is difficult to quantify at this time as specific measures for meeting Canada's commitments have not been developed.

CHANGES IN LEGISLATION

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects the Trust and its unitholders. Tax authorities having jurisdiction over the Trust or the unitholders may disagree with how the Trust calculates its income for tax purposes or could change administrative practices to the detriment of the Trust or the detriment of its unitholders. ARC intends that the Trust will continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and its unitholders.

OPERATIONAL MATTERS

The operation of oil and gas wells involves a number of operating and natural hazards that may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to operating subsidiaries of the Trust and possible liability to third parties. ARC will maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. ARC may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce distributable cash.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Operating costs on most properties have increased steadily over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to certain properties. A reduction of the distributions could result in such circumstances.

NON-RESIDENT OWNERSHIP OF TRUST UNITS

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust intends to comply with the requirements of the Tax Act for "mutual fund trusts" at all relevant times. In this regard, the Trust shall among other things, monitor the ownership of the units to carry out such intentions. The Trust Indenture provides that if at any time the Trust becomes aware that the beneficial owners of 50 per cent or more of the units then outstanding are or may be non-residents or that such a situation is imminent, the Trust shall take such action as it is able and as may be necessary to carry out the foregoing intention.

DEBT SERVICE AND ADDITIONAL FINANCING

Amounts paid in respect of interest and principal on debt will reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants of the agreements with ARC's lenders may also limit distributions. Although ARC believes the credit facilities will be sufficient for the Trust's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or that additional funds will be able to be obtained.

The lenders will be provided with security over substantially all of the assets of ARC. If ARC becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

In the normal course of making capital investments to maintain and expand the oil and gas reserves of the Trust, additional units are issued from treasury that may result in a decline in production per unit and reserves per unit. Additionally, from time to time the Trust issues units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that ARC is required to use cash flow to finance capital expenditures or property acquisitions, to pay debt service charges or to reduce debt, the level of distributable income will be reduced.

EXPANSION OF OPERATIONS

The operations and expertise of management of the Trust are currently focused on conventional oil and gas production and development in the western Canadian sedimentary basin. In the future, the Trust may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Trust being adversely affected.

Additional Information

Additional information relating to ARC can be found on SEDAR at www.sedar.com.

ANNUAL HISTORICAL REVIEW

For the year ended December 31 (Cdn$ thousands, except per unit amounts)	**2005**	2004	2003	2002	2001
FINANCIAL					
Revenue before royalties	**1,165,197**	901,782	743,182	444,835	515,596
Per unit (1)	**6.10**	4.85	4.80	3.72	5.00
Cash flow	**639,511**	448,033	396,180	223,969	260,270
Per unit – basic (1)	**3.35**	2.41	2.56	1.87	2.53
Per unit – diluted	**3.32**	2.38	2.48	1.86	2.54
Net income	**356,935**	241,690	284,559	69,981	130,993
Per unit – basic (5)	**1.90**	1.32	1.88	0.60	1.30
Per unit – diluted	**1.88**	1.31	1.82	0.59	1.32
Cash distributions	**376,566**	329,977	279,328	183,617	234,053
Per unit (2)	**1.99**	1.80	1.80	1.56	2.31
Total assets	**3,251,161**	2,304,998	2,281,775	1,467,918	1,380,004
Total liabilities	**1,415,519**	755,650	730,039	599,252	563,882
Net debt outstanding (4)	**578,086**	264,842	262,071	347,795	288,684
Weighted average units (thousands) (3)	**191,172**	186,105	154,695	119,613	103,062
Units outstanding and issuable at period end (thousands) (3)	**202,039**	188,804	182,777	126,444	111,692
CAPITAL EXPENDITURES					
Geological and geophysical	**9,219**	5,388	5,671	1,966	2,215
Drilling and completions	**200,873**	144,487	110,277	70,074	73,147
Plant and facilities	**55,032**	41,089	36,457	14,357	22,970
Other capital	**3,710**	2,820	3,359	1,881	3,886
Total capital expenditures	**268,834**	193,784	155,764	88,278	102,218
Property acquisitions (dispositions), net	**91,286**	(58,219)	(161,609)	119,113	12,911
Corporate acquisitions (6)	**504,996**	72,009	721,590	–	509,748
Total capital expenditures and net acquisitions	**865,116**	207,574	715,745	207,391	624,877
OPERATING					
Production					
Crude oil (bbl/d)	**23,282**	22,961	22,886	20,655	20,408
Natural gas (mmcf/d)	**173.8**	178.3	164.2	109.8	115.2
Natural gas liquids (bbl/d)	**4,005**	4,191	4,086	3,479	3,511
Total (boe per day 6:1)	**56,254**	56,870	54,335	42,425	43,111
Average prices					
Crude oil ($/bbl)	**61.11**	47.03	36.90	31.63	31.70
Natural gas ($/mcf)	**8.96**	6.78	6.40	4.41	5.72
Natural gas liquids ($/bbl)	**49.92**	39.04	32.19	24.01	31.03
Oil equivalent ($/boe)	**56.54**	43.13	37.29	28.73	32.76
RESERVES (7) (company interest)					
Proved plus probable reserves					
Crude oil and NGL (mbbl)	**163,385**	123,226	129,663	117,241	114,243
Natural gas (bcf)	**741.7**	724.5	720.2	408.8	385.5
Total (mboe)	**286,997**	243,974	249,704	185,371	178,496
TRUST UNIT TRADING (based on intra-day trading)					
Unit prices					
High	**27.58**	17.98	14.87	13.44	13.54
Low	**16.55**	13.50	10.89	11.04	10.25
Close	**26.49**	17.90	14.74	11.90	12.10
Average daily volume (thousands)	**656**	420	430	305	414

Please refer to page 50 for footnote references.

QUARTERLY REVIEW

(Cdn$ thousands, except per unit amounts)	**2005**				2004			
FINANCIAL	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue before royalties	**365,298**	310,249	251,596	238,054	232,112	230,769	233,307	205,594
Per unit (1)	**1.89**	1.62	1.32	1.26	1.23	1.23	1.26	1.12
Cash flow	**207,621**	168,117	121,808	141,965	106,935	110,835	122,249	108,014
Per unit – basic (1)	**1.07**	0.88	0.64	0.75	0.57	0.59	0.66	0.59
Per unit – diluted	**1.07**	0.87	0.63	0.74	0.56	0.59	0.65	0.58
Net income	**130,474**	114,600	73,215	38,646	112,995	38,897	50,338	39,460
Per unit – basic (5)	**0.68**	0.61	0.39	0.21	0.61	0.21	0.28	0.22
Per unit – diluted	**0.68**	0.59	0.38	0.20	0.60	0.21	0.27	0.22
Cash distributions	**115,671**	92,559	84,468	83,867	83,531	83,178	82,053	81,215
Per unit (2)	**0.60**	0.49	0.45	0.45	0.45	0.45	0.45	0.45
Total assets	**3,251,161**	2,483,540	2,427,463	2,303,948	2,304,998	2,316,297	2,309,599	2,278,608
Total liabilities	**1,415,519**	912,160	895,179	785,776	755,650	804,603	768,073	752,166
Net debt outstanding (4)	**578,086**	357,560	366,216	254,252	264,842	220,500	220,074	284,001
Weighted average units (thousands) (3)	**193,445**	191,709	190,315	189,210	188,521	187,629	184,998	183,314
Units outstanding and issuable at period end (thousands) (3)	**202,039**	192,089	191,329	189,609	188,804	188,185	187,296	183,980
CAPITAL EXPENDITURES								
Geological and geophysical	**3,040**	2,258	2,659	1,262	867	828	1,373	2,320
Drilling and completions	**65,690**	65,676	33,465	36,042	39,125	42,553	24,867	37,942
Plant and facilities	**17,031**	14,803	8,703	14,495	6,183	11,668	7,282	15,956
Other capital	**2,020**	317	652	721	1,480	394	605	341
Total capital expenditures	**87,781**	83,054	45,479	52,520	47,655	55,443	34,127	56,559
Property acquisitions (dispositions), net	**3,037**	5,860	78,721	3,668	(1,036)	(5,345)	(53,412)	1,574
Corporate acquisitions (6)	**462,814**	–	42,182	–	41,449	–	30,560	–
Total capital expenditures and net acquisitions	**553,632**	88,914	166,382	56,188	88,068	50,098	11,275	58,133
OPERATING								
Production								
Crude oil (bbl/d)	**25,534**	23,513	22,046	21,993	22,969	22,496	22,720	23,663
Natural gas (mmcf/d)	**177.9**	168.2	173.1	176.1	174.7	177.4	186.7	174.5
Natural gas liquids (bbl/d)	**3,943**	4,047	3,962	4,072	4,097	4,034	4,313	4,323
Total (boe per day 6:1)	**59,120**	55,592	54,860	55,410	56,179	56,096	58,147	57,075
Average prices								
Crude oil ($/bbl)	**62.12**	69.37	58.37	53.63	49.48	51.00	47.43	40.41
Natural gas ($/mcf)	**12.05**	9.08	7.42	7.20	6.82	6.65	6.99	6.64
Natural gas liquids ($/bbl)	**57.14**	50.43	46.13	46.57	43.72	42.30	38.22	32.30
Oil equivalent ($/boe)	**67.16**	60.66	50.40	47.74	44.62	44.54	43.82	39.58
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**27.58**	24.20	20.30	20.40	17.98	17.38	15.74	15.74
Low	**20.45**	19.94	16.88	16.55	14.80	15.02	14.28	13.50
Close	**26.49**	24.10	19.94	18.15	17.90	16.85	15.35	15.64
Average daily volume (thousands)	**653**	599	605	895	456	384	337	502

(1) Based on weighted average trust units plus units issuable for exchangeable shares.
(2) Based on number of trust units outstanding at each cash distribution date.
(3) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio.
(4) Total current and long-term debt net of working capital.
(5) Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures.
(6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.
(7) Established reserves for 2002 and 2001.

GOVERNANCE

In the normal course of making capital investments to maintain and expand the oil and gas reserves of the Trust, ARC is committed to the highest standards for its governance practices and procedures. ARC's governance practices are routinely reviewed, appraised and modified to ensure that they are appropriate for a corporation of ARC's size and stature. ARC's approach to corporate governance meets the guidelines established by the Canadian Securities Administrators ("CSA") as laid out in National Instrument 58-101.

Independence of the Board

ARC's Board comprises eight members, all of whom are "independent" directors, except for the Chief Executive Officer. ARC uses the definition of independence as defined in NI 58-101 that states that a director is independent if the member has no direct or indirect material relationship with the company. A material relationship means a relationship that could, in the opinion of the Board of Directors, reasonably interfere with the exercise of a member's independent judgement.

The Board has determined that none of the directors who serve on its committees has a material relationship with ARC that could reasonably be expected to interfere with the exercise of a director's independent judgment. The Chairman of the Board is an independent director and, in conjunction with the Vice-Chairman, is responsible for managing the affairs of the Board and its committees, including ensuring the Board is organized properly, functions effectively and independently of management and meets its obligations and responsibilities.

Mandate of the Board

The Board of Directors of ARC sees its primary role as the stewardship of ARC and for overseeing the management of the business and affairs of ARC, with the goal of achieving the Trust's fundamental objective of providing long-term superior returns to unitholders. The Board oversees the conduct of the business and management through its review and approval of strategic, operating, capital and financial plans; the identification of the principal risks of the Trust's business and oversight of the implementation of systems to manage such risks; the appointment and performance review of the Chief Executive Officer; the approval of communication policies for the Trust and the review of the integrity of the Trust's internal financial controls and management systems.

Committees of the Board

The Board has established an Audit Committee, a Reserve Committee, a Human Resources and Compensation Committee, a Policy and Board Governance Committee and a Health, Safety and Environment Committee to assist it in the discharge of its duties and responsibilities. All of the committees are comprised of independent directors and report to the Board of Directors of ARC Resources.

AUDIT COMMITTEE

MEMBERS: FRED DYMENT (CHAIR), WALTER DEBONI, MICHAEL KANOVSKY AND MAC VAN WIELINGEN.

The Audit Committee assists the Board in fulfilling its oversight responsibilities with respect to the integrity and completeness of the annual and quarterly financial statements and accompanying management discussion and analysis provided to unitholders and regulatory bodies; compliance with accounting and finance based legal and regulatory requirements; review of the independence and performance of the external auditor, internal accounting systems and procedures. The committee reviews the audit plans of the external auditors and meets with them at the time of each committee meeting, independently of management.

There were eight meetings of the committee in 2005.

RESERVES COMMITTEE

MEMBERS: FRED COLES (CHAIR), FRED DYMENT AND MICHAEL KANOVSKY.

The Reserves Committee assists the Board in meeting their responsibilities to review the qualifications, experience, reserve evaluation approach and costs of the independent engineering firm that performs ARC's reserve evaluation and to review the annual independent engineering report. The committee reviews and recommends for approval by the Board on an annual basis the statements of reserve data and other information specified in National Instrument 51-101. The committee also reviews any other oil and gas reserve report prior to release by ARC to the public and reviews all of the disclosure in the Annual Information Form and elsewhere, related to the oil and gas activities of ARC.

There were six meetings of the committee in 2005.

HUMAN RESOURCES AND COMPENSATION COMMITTEE

MEMBERS: JOHN STEWART (CHAIR), FRED COLES, HERB PINDER AND MAC VAN WIELINGEN.

The Human Resources and Compensation Committee assists the Board in fulfilling its oversight responsibilities with respect to overall human resource policies and procedures; the compensation program for ARC; and in consultation with the Board, undertakes an annual performance review with the President and CEO, and reviews the CEO's appraisal of the other executive officers' performance. The committee reviews the salary, bonus and other remuneration for the executive officers of ARC and makes recommendations on such matters to the CEO. The committee also reviews and recommends for approval to the Board the principal compensation plans of ARC such as the long-term incentive program and any awards under such plans.

There were eight meetings of the committee in 2005.

HEALTH, SAFETY AND ENVIRONMENT COMMITTEE

MEMBERS: WALT DEBONI (CHAIR), FRED COLES AND JOHN STEWART.

The Health, Safety and Environment Committee assists the Board in its responsibility for oversight and due diligence by reviewing, reporting and making recommendations to the Board on the development and implementation of the standards and policies of ARC with respect to the areas of health, safety and environment. This committee meets separately with management of ARC who have responsibility for such matters and reports to the Board.

There were four meetings of the committee in 2005.

POLICY AND BOARD GOVERNANCE COMMITTEE

MEMBERS: WALTER DEBONI (CHAIR), HERB PINDER, JOHN STEWART AND MAC VAN WIELINGEN.

The Policy and Board Governance Committee assists the Board in fulfilling its oversight responsibilities with respect to reviewing the effectiveness of the Board and its Committees; developing and reviewing ARC's approach to board governance matters; and reviewing, developing and recommending to the Board for approval procedures designed to ensure that the Board can function independently of management. The committee annually reviews the need to recruit and recommend new members to fill Board vacancies giving consideration to the competencies, skills and personal qualities of the candidates and of the existing Board, and recommends to the Board the nominees for election at each annual meeting. The effectiveness of individual board members and the board is reviewed through a yearly self assessment and inquiry questionnaire.

There were six meetings of the committee in 2005.

MANAGEMENT'S RESPONSIBILITY

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In Management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles, have been prepared within acceptable limits of materiality, and have utilized supportable, reasonable estimates.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer and chief financial officer.

The Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit Committee. The Audit Committee is composed entirely of independent directors, and includes at least one director with financial expertise. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors and reviews their fees.

The consolidated financial statements have been audited by Deloitte & Touche LLP, independent auditors, in accordance with generally accepted auditing standards on behalf of the unitholders.

John Dielwart

JOHN P. DIELWART
PRESIDENT AND CHIEF EXECUTIVE OFFICER

Steven W Sinclair

STEVEN W. SINCLAIR
SENIOR VICE-PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER

CALGARY, ALBERTA
FEBRUARY 3, 2005

ARC ENERGY TRUST AUDITORS' REPORT

TO THE UNITHOLDERS OF ARC ENERGY TRUST:

We have audited the consolidated balance sheets of ARC Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS

CALGARY, ALBERTA
FEBRUARY 3, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31 (Cdn$ thousands)	**2005**	2004
ASSETS		
Current assets		
Cash and cash equivalents	**$ –**	$ 4,413
Accounts receivable	**122,956**	72,881
Prepaid expenses	**14,020**	9,878
Commodity and foreign currency contracts (Note 9)	**3,125**	22,294
	140,101	109,466
Reclamation fund (Note 4)	**23,491**	21,294
Property, plant and equipment (Note 5)	**2,929,977**	2,016,646
Goodwill	**157,592**	157,592
Total assets	**$ 3,251,161**	$ 2,304,998
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 148,587**	$ 103,572
Cash distributions payable	**39,839**	27,893
Current portion of long term debt (Note 6)	**–**	8,715
Commodity and foreign currency contracts (Note 9)	**7,167**	26,336
	195,593	166,516
Long-term debt (Note 6)	**526,636**	211,834
Other long-term liabilities (Note 7)	**12,360**	3,893
Asset retirement obligations (Note 8)	**165,053**	73,001
Future income taxes (Note 10)	**515,877**	300,406
Total liabilities	**1,415,519**	755,650
COMMITMENTS AND CONTINGENCIES (Note 18)		
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 12)	**37,494**	35,967
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 11)	**2,230,842**	1,926,351
Contributed surplus (Note 14)	**6,382**	6,475
Accumulated earnings	**1,235,742**	878,807
Accumulated cash distributions (Note 13)	**(1,674,818)**	(1,298,252)
Total unitholders' equity	**1,798,148**	1,513,381
Total liabilities and unitholders' equity	**$ 3,251,161**	$ 2,304,998

See accompanying notes to the consolidated financial statements.

M Van Wielingen

MAC H. VAN WIELINGEN
DIRECTOR

F Dyment

FRED DYMENT
DIRECTOR

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

For the years ended December 31 (Cdn$ thousands, except per unit amounts)	**2005**	2004
REVENUES		
Oil, natural gas, and natural gas liquids	**$ 1,165,197**	$ 901,782
Royalties	**(235,293)**	(177,032)
	929,904	724,750
Realized loss on commodity and foreign currency contracts (Note 9)	**(87,558)**	(86,909)
Unrealized gain (loss) on commodity and foreign currency contracts	**–**	841
	842,346	638,682
EXPENSES		
Transportation	**14,289**	14,798
Operating	**142,240**	139,716
General and administrative	**42,746**	29,512
Interest on long-term debt (Note 6)	**16,946**	13,320
Depletion, depreciation and accretion (Notes 5 and 8)	**264,515**	239,674
Gain on foreign exchange (Note 17)	**(6,412)**	(20,713)
	474,324	416,307
Income before taxes	**368,022**	222,375
Capital and other taxes	**(3,882)**	(2,834)
Future income tax (expense) recovery (Note 10)	**(1,660)**	26,100
Net income before non-controlling interest	**362,480**	245,641
Non-controlling interest (Note 12)	**(5,545)**	(3,951)
Net income	**356,935**	241,690
Accumulated earnings, beginning of year	**878,807**	637,117
Accumulated earnings, end of year	**$ 1,235,742**	$ 878,807
Net income per unit (Note 16)		
Basic	**$ 1.90**	$ 1.32
Diluted	**$ 1.88**	$ 1.31

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31 (Cdn$ thousands)	**2005**	2004
CASH FLOW FROM OPERATING ACTIVITIES		
Net income after non-controlling interest	**$ 356,935**	$ 241,690
Add items not involving cash:		
Non-controlling interest	**5,545**	3,951
Future income tax expense (recovery)	**1,660**	(26,100)
Depletion, depreciation and accretion (Notes 5 and 8)	**264,515**	239,674
Non-cash gain on commodity and foreign currency contracts	**-**	(841)
Non-cash gain on foreign exchange (Note 17)	**(6,359)**	(18,427)
Non-cash trust unit incentive compensation (Notes 14 and 15)	**17,215**	8,086
Expenditures on site reclamation and restoration	**(4,881)**	(3,232)
Change in non-cash working capital	**(17,919)**	1,617
	616,711	446,418
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Borrowings (repayments) under revolving credit facilities	**258,190**	(162,555)
Issuance of senior secured notes	**62,478**	177,322
Repayment of senior secured notes	**(8,214)**	(8,347)
Issue of trust units	**259,691**	19,301
Trust unit issue costs	**(12,218)**	(152)
Cash distributions paid, net of distribution reinvestment (Note 13)	**(318,238)**	(301,936)
Payment of retention bonus	**(1,000)**	(1,000)
Change in non-cash working capital	**(179)**	(397)
	240,510	(277,764)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Corporate acquisitions, net of cash received (Note 3)	**(504,996)**	(39,385)
Acquisition of petroleum and natural gas properties	**(93,824)**	529
Proceeds on disposition of petroleum and natural gas properties	**2,538**	57,691
Capital expenditures	**(257,895)**	(192,591)
Net reclamation fund contributions (Note 4)	**(2,197)**	(4,113)
Change in non-cash working capital	**(5,260)**	1,333
	(861,634)	(176,536)
DECREASE IN CASH AND CASH EQUIVALENTS	**(4,413)**	(7,882)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**4,413**	12,295
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ -**	$ 4,413

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004 (all tabular amounts in thousands Cdn$ except per unit and volume amounts)

1. STRUCTURE OF THE TRUST

ARC Energy Trust ("ARC" or the "Trust") was formed on May 7, 1996 pursuant to a Trust indenture (the "Trust Indenture") that has been amended from time to time, most recently on May 12, 2005. Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units.

The Trust was created for the purposes of issuing trust units to the public and investing the funds so raised to purchase a royalty in the properties of ARC Resources Ltd. ("ARC Resources") and ARC Sask Energy Trust ("ARC Sask"). The Trust Indenture was amended on June 7, 1999 to convert the Trust from a closed-end to an open-ended investment Trust. The current business of the Trust includes the investment in all types of energy business-related assets including, but not limited to, petroleum and natural gas-related assets, gathering, processing and transportation assets. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of the net cash proceeds from these activities to the unitholders.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("US GAAP") and to the extent that they affect the Trust, these differences are described in Note 20. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and accretion of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to "the Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

REVENUE RECOGNITION

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids ("NGLs") owned by the Trust are recognized when title passes from the Trust to its customers.

TRANSPORTATION

Costs paid by the Trust for the transportation of natural gas, crude oil and NGLs from the wellhead to the point of title transfer are recognized when the transportation is provided.

JOINT VENTURE

The Trust conducts many of its oil and gas production activities through joint ventures and the financial statements reflect only the Trust's proportionate interest in such activities.

DEPLETION AND DEPRECIATION

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands, plus estimated future development costs of proved undeveloped reserves, including future estimated asset retirement costs; and

(c) relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

UNIT BASED COMPENSATION

The Trust has established a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust accounts for the rights using the fair value method, whereby the fair value of rights is determined on the date on which fair value can initially be determined. The fair value is then recorded as compensation expense over the period that the rights vest, with a corresponding increase to contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

WHOLE TRUST UNIT INCENTIVE PLAN COMPENSATION

The Trust has established a Whole Trust Unit Incentive Plan (the "Whole Unit Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. Compensation expense associated with the Whole Unit Plan is granted in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs") and is determined based on the intrinsic value of the Whole Trust Units at each period end. The intrinsic valuation method is used as participants of the Whole Unit Plan receive a cash payment on a fixed vesting date. This valuation incorporates the period end trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying trust unit price. In addition, compensation expense is deferred and recognized in earnings over the vesting period of the Whole Unit Plan with a corresponding increase or decrease in liabilities. Classification between accrued liabilities and other long-term liabilities is dependent on the expected payout date.

The Trust charges amounts relating to head office employees to general and administrative expense, amounts relating to field employees to operating expense and amounts relating to geologists and geophysicists to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for RTUs and PTUs that will not vest. Rather, the Trust accounts for actual forfeitures as they occur.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

PROPERTY, PLANT AND EQUIPMENT ("PP&E")

The Trust follows the full cost method of accounting. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 per cent or more.

IMPAIRMENT

The Trust places a limit on the aggregate carrying value of PP&E, which may be amortized against revenues of future periods.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Trust's future cash flows would be recorded as a permanent impairment.

The cost of unproved properties is excluded from the impairment test described above and subject to a separate impairment test.

GOODWILL

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity (consolidated Trust) compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

ASSET RETIREMENT OBLIGATIONS ("ARO")

The Trust recognizes the fair value of an ARO in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes, if any, to the estimate will be applied on a prospective basis. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Trust's earnings in the period in which the settlement occurs.

INCOME TAXES

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Basic net income per unit is computed by dividing the net income by the weighted average number of units outstanding during the period. Diluted net income per unit amounts are calculated giving effect to the potential dilution that would occur if rights were exercised at the beginning of the period. The treasury stock method assumes that proceeds received from the exercise of in-the-money rights and any unrecognized trust unit incentive compensation are used to repurchase units at the average market price.

DERIVATIVE FINANCIAL INSTRUMENTS

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify or have not been designated as effective hedges for accounting purposes.

For derivative instruments that do qualify as effective accounting hedges, policies and procedures are in place to ensure that the required documentation and approvals are in place. This documentation specifically ties the derivative financial instrument to its use, and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transactions. This would include linking the particular derivative to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Trust assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair value or cash flows of the hedged item.

Realized and unrealized gains and losses associated with hedging instruments that have been terminated or cease to be effective prior to maturity, are deferred on the consolidated balance sheet and recognized in income in the period in which the underlying hedged transaction is recognized.

For transactions that do not qualify for hedge accounting, the Trust applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizing changes in the fair value of the instruments in the statement of income for the current period.

FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the consolidated balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

NON-CONTROLLING INTEREST

The Trust must record non-controlling interest when exchangeable shares issued by a subsidiary of the Trust are transferable to third parties. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. Net income is reduced for the portion of earnings attributable to the non-controlling interest. As the exchangeable shares are converted to trust units, the non-controlling interest on the consolidated balance sheet is reduced by the cumulative book value of the exchangeable shares and unitholders' capital is increased by the corresponding amount.

RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2005.

3. CORPORATE ACQUISITIONS

REDWATER AND NORTH PEMBINA CARDIUM UNIT

On December 16, 2005 the Trust acquired all of the issued and outstanding shares of three legal entities, 3115151 Nova Scotia Company, 3115152 Nova Scotia Company and 3115153 Nova Scotia Company which together hold the Redwater and North Pembina Cardium Unit assets (collectively "Redwater and NPCU") for total consideration of $462.8 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired		
Working capital deficit	$	(629)
Property, plant and equipment		729,482
Asset retirement obligations		(70,700)
Future income taxes		(195,339)
Total net assets acquired	**$**	**462,814**

Consideration Paid		
Cash consideration and fees paid	$	462,814
Total consideration paid	**$**	**462,814**

The acquisition of Redwater and NPCU has been accounted for as an asset acquisition pursuant to EIC-124.

In addition to consideration paid, the Trust committed to making contributions to a restricted reclamation fund as detailed in Note 18.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $463.4 million and the associated tax basis of $93.3 million.

These consolidated financial statements incorporate the operations of Redwater and NPCU from December 16, 2005.

ROMULUS EXPLORATION INC.

On June 30, 2005, the Trust acquired all of the issued and outstanding shares of Romulus Exploration Inc. ("Romulus") for total consideration of $42.2 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired		
Working capital deficit	$	(1,359)
Property, plant and equipment		62,456
Asset retirement obligations		(443)
Future income taxes		(18,472)
Total net assets acquired	**$**	**42,182**

Consideration Paid		
Cash and fees paid	$	42,182
Total consideration paid	**$**	**42,182**

The acquisition of Romulus has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $44 million and the associated tax basis of $9 million.

These consolidated financial statements incorporate the operations of Romulus from June 30, 2005.

HARRINGTON & BIBLER

On December 31, 2004, the Trust acquired all of the issued and outstanding shares of four legal entities – Harrington Oil & Gas Ltd., Bibler Oil & Gas Ltd., Lesco Oil & Gas Ltd., and Bibco Oil & Gas Ltd. ("Harrington & Bibler") – for total consideration of $41.4 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired		
Working capital surplus (including cash of $2,124)	$	3,479
Property, plant and equipment		55,229
Future income taxes		(17,259)
Total net assets acquired	**$**	**41,449**

Consideration Paid		
Cash and fees paid	$	41,449
Total consideration paid	**$**	**41,449**

The acquisition of Harrington & Bibler has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $38 million and the associated tax basis of $5.3 million.

These consolidated financial statements incorporate the results of operations of the acquired Harrington & Bibler properties from December 31, 2004.

UNITED PRESTVILLE LTD.

On June 8, 2004, the Trust acquired all of the issued and outstanding shares of United Prestville Ltd. ("United Prestville") for total consideration of $30.6 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired		
Working capital deficit	$	(2,569)
Property, plant and equipment		40,412
Future income taxes		(7,283)
Total net assets acquired	**$**	**30,560**

Consideration Paid		
Cash fees paid	$	60
Trust units issued		30,500
Total consideration paid	**$**	**30,560**

The acquisition of United Prestville has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $33.1 million and the associated tax basis of $19.3 million.

These consolidated financial statements incorporate the operations of United Prestville from June 8, 2004.

4. RECLAMATION FUND

	2005	2004
Balance, beginning of year	**$ 21,294**	$ 17,181
Contributions	**6,000**	6,000
Reimbursed expenditures (1)	**(4,644)**	(3,097)
Interest earned on fund	**841**	1,210
Balance, end of year	**$ 23,491**	$ 21,294

(1) Amount differs from actual expenditures incurred by the Trust due to timing differences.

A reclamation fund was established to fund future asset retirement obligation costs. The Board of Directors of ARC Resources has approved voluntary contributions over a 20 year period that result in minimum annual contributions of $6 million ($6 million in 2004) based upon properties owned as at December 31, 2005. In addition, the Trust has committed to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition, detailed in Note 18. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders.

5. PROPERTY, PLANT AND EQUIPMENT

	2005	2004
Property, plant and equipment, at cost	**$ 4,141,958**	$ 2,969,319
Accumulated depletion and depreciation	**(1,211,981)**	(952,673)
Property, plant and equipment, net	**$ 2,929,977**	$ 2,016,646

The calculation of 2005 depletion and depreciation included an estimated $488 million ($374.2 million in 2004) for future development costs associated with proved undeveloped reserves and excluded $58.9 million ($52.5 million in 2004) for the cost value of unproved properties.

The Trust performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of PP&E. Based on the calculation, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's PP&E at December 31, 2005. The benchmark prices used in the calculation are as follows:

Year	WTI Oil ($US/bbl)	AECO Gas (Cdn$/mmbtu)	USD/CAD Exchange Rates
2006	57.00	10.60	0.85
2007	55.00	9.25	0.85
2008	51.00	8.00	0.85
2009	48.00	7.50	0.85
2010	46.50	7.20	0.85
2011 - 2016	46.50	7.15	0.85
Remainder (1)	2.0%	2.0%	0.85

(1) Percentage change represents the change in each year after 2016 to the end of the reserve life.

6. LONG-TERM DEBT

	2005	2004
Revolving credit facilities		
Syndicated credit facility (1)	**$ 254,680**	$ –
Working capital facility	**3,800**	290
Senior secured notes		
8.05% USD Note	**–**	33,701
5.42% USD Note	**87,443**	–
4.94% USD Note	**34,977**	36,108
4.62% USD Note	**72,868**	75,225
5.10% USD Note	**72,868**	75,225
Total debt outstanding	**$ 526,636**	$ 220,549
Current portion of debt	**–**	8,715
Long-term debt	**$ 526,636**	$ 211,834

(1) Amount borrowed under the syndicated credit facility includes $2.9 million of outstanding cheques in excess of bank balance.

In April 2004, the Trust consolidated its credit facilities into one syndicated facility. The syndication did not impact security or covenants under the credit facility. As at December 31, 2005, the Trust has one syndicated credit facility and one working capital facility to a combined maximum of $950 million, less the amount of the outstanding senior secured notes.

Amounts due under the working capital facility and the senior secured notes in the next 12 months have not been included in current liabilities as management has the ability and intent to refinance this amount through the syndicated credit facility.

Security for the senior secured notes is in the form of floating charges on all lands and assignments. The senior secured notes rank pari passu to the revolving credit facilities.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank in priority to cash distributions payable to unitholders. Should the properties securing this debt generate insufficient revenue to repay the outstanding balances, the unitholders have no direct liability.

Interest paid during the year did not differ significantly from interest expense.

REVOLVING CREDIT FACILITIES

The syndicated revolving credit facility has a 364 day extendable revolving period and a two year term. Borrowings under the facility bear interest at bank prime (five per cent and 4.25 per cent at December 31, 2005 and December 31, 2004, respectively) or, at the Trust's option, Canadian dollar or US dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. The term date of the current credit facility is March 28, 2006.

In the event that the revolving periods are not extended, the loan balance will become repayable over a two year term period with 20 per cent of the loan balance outstanding on the term date payable on March 28, 2007 followed by three quarterly payments of five per cent of the loan balance. The remaining 65 per cent of the loan balance is payable in one lump sum at the end of the term period. Collateral for the loan is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

The working capital facility allows for maximum borrowings of $25 million and is due and payable immediately upon demand by the bank. The facility is secured and is subject to the same covenants as the credit facility.

8.05 PER CENT, 5.42 PER CENT AND 4.94 PER CENT SENIOR SECURED USD NOTES
These senior secured notes were issued in three separate issues pursuant to an Uncommitted Master Shelf Agreement. The US$35 million senior secured notes were issued in 2000, bore interest at 8.05 per cent, and had a remaining weighted average term of 2.3 years at January 1, 2005. During the year, the Trust repaid the total principal outstanding, incurring a make whole-premium in the amount of US$1.1 million, which was paid in order to early settle the debt. This make-whole premium was charged to interest expense in the year.

In conjunction with the early retirement of the above notes, additional US$75 million notes were issued on December 15, 2005. These notes bear interest at 5.42 per cent, have a remaining final term of 12 years (remaining weighted average term of 8.6 years) and require equal principal repayments over an eight year period commencing in 2010.

The US$30 million senior secured notes were issued in 2002, bear interest at 4.94 per cent, have a remaining final life of 4.8 years (remaining average life of 2.8 years) and require equal principal payments of US$6 million over a five year period commencing in 2006.

4.62 PER CENT AND 5.10 PER CENT SENIOR SECURED USD NOTES
These notes were issued on April 27, 2004 via a private placement in two tranches of US$62.5 million each. The first tranche of US$62.5 million bears interest at 4.62 per cent and has a remaining final term of 8.3 years (remaining weighted average term of 5.9 years) and require equal principal repayments over a six year period commencing 2009. Immediately following the issuance, the Trust entered into interest rate swap contracts that effectively changed the interest rate from fixed to floating (see Note 9). The second tranche of US$62.5 million bears interest at 5.10 per cent and has a remaining final term of 10.3 years (remaining weighted average term of 8.4 years). Repayments of the notes will occur in years 2012 through 2016.

7. OTHER LONG-TERM LIABILITIES

	2005	2004
Accrued long-term incentive compensation	**$ 11,360**	$ 1,893
Retention bonuses	**1,000**	2,000
Total other long-term liabilities	**$ 12,360**	$ 3,893

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2005 (see Note 15). This amount is payable in 2007 through 2008.

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2007.

8. ASSET RETIREMENT OBLIGATIONS ("ARO")

The total future ARO was estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total ARO to be $165.1 million as at December 31, 2005 (2004 - $73 million) based on a total future undiscounted liability of $603.4 million ($247 million in 2004). These payments are expected to be made over the next 61 years with the bulk of payments being made in years 2016 to 2025 and 2046 to 2055. The Trust's weighted average credit adjusted risk free rate of 5.6 per cent (6.9 per cent in 2004) and an inflation rate of two per cent (1.5 per cent in 2004) were used to calculate the present value of the ARO. During the year, no gains or losses were recognized on settlements of ARO.

The following table reconciles the Trust's ARO:

	2005	2004
Carrying amount, beginning of year	**$ 73,001**	$ 66,657
Increase in liabilities relating to corporate acquisitions	**71,143**	–
Increase in liabilities relating to development activities	**5,096**	7,524
Increase (decrease) in liabilities relating to change in estimate	**15,487**	(2,528)
Settlement of liabilities during the year	**(4,881)**	(3,232)
Accretion expense	**5,207**	4,580
Carrying amount, end of year	**$ 165,053**	$ 73,001

9. FINANCIAL INSTRUMENTS

The Trust is exposed to a number of financial risks including the following items as part of its normal course of business:

RISK FACTORS

A) CREDIT RISK

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only highly rated entities and reviewing its exposure to individual entities on a regular basis. With respect to counterparties to financial instruments the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

B) VOLATILITY OF OIL AND NATURAL GAS PRICES

The Trust's operational results and financial condition, and therefore the amount of distributions paid to the unitholders are dependent on the prices received for oil and natural gas production. Oil and gas prices have fluctuated widely during recent years and are determined by economic, and in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Trust's financial condition and therefore on the distributions to the unitholders. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivatives. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

C) VARIATIONS IN INTEREST RATES AND FOREIGN EXCHANGE RATES

Increases in interest rates could result in a significant increase in the amount the Trust pays to service variable interest debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate that may fluctuate over time. Variations in the exchange rate of the Canadian dollar could have significant positive or negative impact on future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/US exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

FINANCIAL INSTRUMENTS

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation fund, current liabilities, other long-term liabilities, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2005 and 2004, there were no significant differences between the carrying value of these financial instruments and their estimated fair value due to their short term nature.

The fair value of the US$230 million fixed rate senior secured approximated Cdn$269 million as at December 31, 2005 and will vary with changes in interest rates (2004 – US$183 million outstanding approximated Cdn$219 million).

DERIVATIVE CONTRACTS

During 2005, the Trust terminated certain 2006 crude oil and foreign currency contracts resulting in a payment of $6.1 million dollars (2004 – $4.9 million). This amount reduced net income in the year.

Following is a summary of all derivative contracts in place as at December 31, 2005 in order to mitigate the risks discussed above:

Financial WTI Crude Oil Contracts

Term	Contract	Volume (bbl/d)	Bought Put (US$/bbl)	Sold Put (US$/bbl)
2006				
Jan 06 – Mar 06	Bought Put	3,000	50.00	–
Jan 06 – Mar 06	Put Spread	1,000	55.00	45.00
Jan 06 – Jun 06	Put Spread	2,000	50.00	40.00
Jan 06 – Dec 06	Bought Put	1,000	55.00	–
Jan 06 – Dec 06	Put Spread	1,000	55.00	45.00
Apr 06 – Dec 06	Bought Put	2,000	50.00	–
Apr 06 – Dec 06	Put Spread	2,000	55.00	45.00
Annual Weighted Average		**6,992**	**52.68**	**43.68**

Financial AECO Natural Gas Contracts

Term	Contract	Volume (GJ/d)	Bought Put (Cdn$/GJ)	Sold Put (Cdn$/GJ)
2006				
Jan 06 – Mar 06	Bought Put	10,000	8.00	–
Jan 06 – Mar 06	Put Spread	20,000	8.50	6.50
Mar 06 – Mar 06	Put Spread	10,000	10.00	8.00
Apr 06 – Oct 06	Put Spread	30,000	8.00	6.00
Annual Weighted Average		**25,836**	**8.16**	**6.18**

Financial AECO/NYMEX Natural Gas Basis Contracts

Term	Contract	Volume (mmbtu/d)	Bought Put (US$/mmbtu)
2006			
Jan 06 – Mar 06	Bought Put	10,000	8.00
Annual Weighted Average		**2,466**	**8.00**

Financial Foreign Exchange Contracts

Term	Contract	Volume (millions US$)	Swap (Cdn$/US$)	Swap (US$/Cdn$)
USD Sales Contracts				
2006				
Jan 06 – Jun 06	Swap	37.1	1.2239	0.8172
Jan 06 – Dec 06	Swap	60.0	1.1659	0.8577
Annual Weighted Average		**78.6**	**1.1880**	**0.8417**

Term	Contract	Volume (millions US$)	Swap (Cdn$/US$)	Swap (US$/Cdn$)
USD Purchase Contracts				
2006				
Oct 06 – Dec 06	Swap	15.0	1.1685	0.8558
Annual Weighted Average		**3.8**	**1.1685**	**0.8558**

Financial Electricity Contracts (1)

Term	Contract	Volume (MWh)	Swap (Cdn$/MWh)
Jan 06 – Dec 10	Swap	5.0	63.00

(1) Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts (1)

Term	Contract	Principal (millions US$)	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jan 06 – Apr 14	Swap	30.5	4.62	38.5 bps
Jan 06 – Apr 14	Swap	32.0	4.62	(25.5 bps)
Total and Annual Weighted Average		**62.5**	**4.62**	**5.5 bps**

(1) Interest rate swap contracts have an optional termination date of April 27, 2009. The Trust has the option to extend the optional termination date by one year on the anniversary of the trade date each year until April 2009. Starting in 2009, the contract amount decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus a spread and receives the fixed interest rate.

The Trust has designated its fixed price electricity contract as an effective accounting hedge as at January 1, 2004. A realized gain of $0.3 million ($0.4 million loss in 2004) on the electricity contract has been included in operating costs. The fair value unrealized loss on the electricity contract of $0.2 million has not been recorded on the consolidated balance sheet at December 31, 2005.

Previously the Trust had entered into two interest rate swap contracts to manage the Trust's interest rate exposure on debt instruments. These contracts were designated as effective accounting hedges on the contract date. During the year one of these contracts was unwound at a nominal cost. In November 2005 the Trust entered into a new interest rate swap contract which it also designated as an effective accounting hedge. A realized gain of $0.5 million for the year on the interest rate swap contracts has been included in interest expense ($1.4 million gain in 2004). The fair value unrealized loss on the remaining two interest rate swap contracts of $1 million has not been recorded on the consolidated balance sheet at December 31, 2005.

None of the Trust's commodity and foreign currency contracts have been designated as effective accounting hedges. Accordingly, all commodity and foreign currency contracts have been accounted as assets and liabilities in the consolidated balance sheet based on their fair values.

The following table reconciles the movement in the fair value of the Trust's financial commodity and foreign currency contracts that have not been designated as effective accounting hedges:

	2005	2004
Fair value, beginning of year (1)	**$ (4,042)**	$ (14,575)
Fair value, end of year	**(4,042)**	(4,042)
Change in fair value of contracts in the year (1)	**-**	10,533
Realized losses in the year	**(87,558)**	(86,909)
Non-cash amortization of crystallized hedging gains	**-**	4,883
Amortization of opening mark to market loss	**-**	(14,575)
Loss on commodity and foreign currency contracts (1)	**$ (87,558)**	$ (86,068)
Commodity and foreign currency contracts liability	**$ (7,167)**	$ (26,336)
Commodity and foreign currency contract asset	**$ 3,125**	$ 22,294

(1) Excludes the fixed price electricity contract and interest rate swap contracts that were accounted for as effective accounting hedges.

Upon implementation of the new hedge accounting guideline on January 1, 2004, the Trust recorded a liability and corresponding deferred hedge loss of $14.6 million for the fair value of the contracts at that time. The opening deferred hedge loss was amortized to income over the terms of the contracts in place at January 1, 2004. As at December 31, 2004, the deferred hedge loss had been fully amortized. At December 31, 2005, the fair value of the contracts that were not designated as accounting hedges was a loss of $4 million ($4 million in 2004).

The Trust recorded a loss on commodity and foreign currency contracts of $87.6 million in the statement of income for 2005 ($86.1 million in 2004). This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges. During the year, no unrealized gain/loss was recognized as there was no over-all change in fair value of the contracts ($10.5 million unrealized gain in 2004). Realized cash losses on contracts during the year of $87.6 million ($86.9 million in 2004) and amortization expense of $nil of the opening deferred hedge loss ($14.6 million in 2004) have been included in this amount. In addition, this amount includes a non-cash amortization gain of $nil ($4.9 million in 2004) relating to contracts that were previously recorded on the consolidated balance sheet.

10. FUTURE INCOME TAXES

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before future income tax recovery as follows:

	2005	2004
Income before future income tax expense and recovery	**$ 364,140**	$ 219,541
Expected income tax expense at statutory rates	**136,990**	85,410
Effect on income tax of:		
Net income of the Trust	**(111,687)**	(86,547)
Effect of change in corporate tax rate	**(4,885)**	(5,861)
Resource allowance	**(20,036)**	(13,341)
Unrealized (gain) on foreign exchange	**(1,588)**	(8,412)
Non-deductible crown charges	**1,265**	1,304
Alberta Royalty Tax Credit	**141**	244
Capital tax	**1,460**	1,103
Future income tax expense (recovery)	**$ 1,660**	$ (26,100)

The net future income tax liability is comprised of the following:

	2005	2004
Future tax liabilities:		
Capital assets in excess of tax value	**$ 569,812**	$ 345,987
Future tax assets:		
Non-capital losses	**(1,509)**	(19,429)
Asset retirement obligations	**(45,755)**	(19,434)
Commodity and foreign currency contracts	**(1,364)**	(1,384)
Attributed Canadian royalty income	**(5,289)**	(5,289)
Deductible share issue costs	**(18)**	(45)
Net future income tax liability	**$ 515,877**	$ 300,406

The petroleum and natural gas properties and facilities owned by the Trust's corporate subsidiaries have an approximate tax basis of $567.2 million ($364.6 million in 2004) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $4.5 million ($56.7 million in 2004) that expire in the years through 2010.

$0.9 million of current income tax was accrued for in 2005 relating to a predecessor company. No current income taxes were paid or payable in 2004.

11. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million units of which 199.1 million units were issued and outstanding as at December 31, 2005 (185.8 million as at December 31, 2004).

On December 23, 2005, the Trust issued nine million units at $26.65 per unit for proceeds of $239.9 ($227.6 million net of trust unit issue costs) pursuant to a public offering prospectus dated December 16, 2005.

The Trust has in place a Distribution Reinvestment and Optional Cash Payment Program Plan ("DRIP") in conjunction with the Trust's transfer agent to provide the option for unitholders to reinvest cash distributions into additional units issued from treasury at a five per cent discount to the prevailing market price with no additional fees or commissions.

The Trust is an open ended mutual fund under which unitholders have the right to request redemption directly from the Trust. Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the date units are tendered or 90 per cent of the weighted average trading price for the 10 day trading period commencing on the tender date. Cash payments for units tendered for redemption are limited to $100,000 per month with redemption requests in excess of this amount eligible to receive a note from ARC Resources for a maximum of $500 million accruing interest at six per cent and repayable within 15 years.

	2005		2004	
	Number of Trust Units	**$**	Number of Trust Units	$
Balance, beginning of year	**185,822**	**1,926,351**	179,780	1,843,112
Issued for cash	**9,000**	**239,850**	–	–
Issued for properties (Note 3)	**–**	**–**	2,032	30,500
Issued on conversion of ARL exchangeable shares (Note 12)	**333**	**4,018**	363	4,295
Issued on exercise of employee rights (Note 14)	**1,500**	**24,052**	1,751	20,672
Distribution reinvestment program	**2,449**	**48,789**	1,896	27,924
Trust unit issue costs	**–**	**(12,218)**	–	(152)
Balance, end of year	**199,104**	**2,230,842**	185,822	1,926,351

12. EXCHANGEABLE SHARES

The ARC Resources exchangeable shares ("ARL Exchangeable Shares") were issued on January 31, 2001 at $11.36 per exchangeable share as partial consideration for the Startech Energy Inc. acquisition. The issue price of the exchangeable shares was determined based on the weighted average trading price of units preceding the date of announcement of the acquisition. The ARL Exchangeable Shares had an exchange ratio of 1:1 at the time of issuance.

ARL Exchangeable Shares can be converted (at the option of the holder) into units at any time. The number of units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average unit price preceding the record date. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for units on or after February 1, 2004 until February 1, 2010. The ARL Exchangeable Shares are publicly traded.

ARL EXCHANGEABLE SHARES	**2005**	2004
Balance, beginning of year	**1,784**	2,011
Exchanged for trust units	**(189)**	(227)
Balance, end of year	**1,595**	1,784
Exchange ratio, end of year	**1.83996**	1.67183
Trust units issuable upon conversion, end of year	**2,935**	2,982

The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of income represents the cumulative share of net income attributable to the non-controlling interest based on the units issuable for exchangeable shares in proportion to total units issued and issuable at each period end.

Following is a summary of the non-controlling interest for 2005 and 2004:

	2005	2004
Non-controlling interest, beginning of year	**$ 35,967**	$ 36,311
Reduction of book value for conversion to trust units	**(4,018)**	(4,295)
Current period net income attributable to non-controlling interest	**5,545**	3,951
Non-controlling interest, end of year	**$ 37,494**	$ 35,967
Accumulated earnings attributable to non-controlling interest	**$ 20,684**	$ 15,139

13. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash flow from operating activities adjusted for changes in non-cash working capital and expenditures on site restoration and reclamation, is reduced by reclamation fund contributions including interest earned on the fund and a portion of capital expenditures. The portion of cash flow withheld to fund capital expenditures is at the discretion of the Board of Directors.

	2005	2004
Cash flow from operating activities	**$ 616,711**	$ 446,418
Change in non-cash working capital	**17,919**	(1,617)
Expenditures on site reclamation and restoration	**4,881**	3,232
Cash flow from operating activities after the above adjustments	**$ 639,511**	$ 448,033
Deduct:		
Cash withheld to fund current period capital expenditures	**(256,104)**	(110,846)
Reclamation fund contributions and interest earned on fund	**(6,841)**	(7,210)
Cash distributions (1)	**376,566**	329,977
Accumulated cash distributions, beginning of year	**1,298,252**	968,275
Accumulated cash distributions, end of year	**$ 1,674,818**	$ 1,298,252
Cash distributions per unit (2)	**$ 1.99**	$ 1.80
Accumulated cash distributions per unit, beginning of year	**14.24**	12.44
Accumulated cash distributions per unit, end of year	**$ 16.23**	$ 14.24

(1) Cash distributions include non-cash amounts of $58.3 million ($28 million – 2004). These amounts relate to the distribution reinvestment program.
(2) Cash distributions per unit reflect the sum of the per unit amounts declared monthly to unitholders.

14. TRUST UNIT INCENTIVE RIGHTS PLAN

The Trust Unit Incentive Rights Plan (the "Rights Plan") was established in 1999 that authorized the Trust to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase units, of which 7,866,088 were granted to December 31, 2005. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the units as at the date of grant and the maximum term of each right is not to exceed 10 years. In general, these rights have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In addition, the exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds 2.5 per cent (10 per cent annually) of the Trust's net book value of property, plant and equipment (the "Excess Distribution"), as determined by the Trust.

During the year, the Trust did not grant any rights (27,000 rights granted in 2004 at an exercise price of $15.42 per unit). No future rights will be issued as the rights plan was replaced with a Whole Unit Plan during 2004 (see Note 15). The existing Rights Plan will be in place until the remaining 1.3 million rights outstanding as at December 31, 2005 are exercised or cancelled.

A summary of the changes in rights outstanding under the Rights Plan is as follows:

	2005		2004	
	Number of Rights	**Weighted Average Exercise Price ($)**	Number of Rights	Weighted Average Exercise Price ($)
Balance, beginning of year	**3,009**	**10.92**	4,869	11.29
Granted	**–**	**–**	27	15.42
Exercised	**(1,500)**	**11.60**	(1,751)	10.57
Cancelled	**(160)**	**10.99**	(136)	11.60
Balance before reduction of exercise price	**1,349**	**11.10**	3,009	11.72
Reduction of exercise price (1)	**–**	**(0.88)**	–	(0.80)
Balance, end of year	**1,349**	**10.22**	3,009	10.92

(1) The holder of the right has the option to exercise rights held at the original grant price or a reduced exercise price.

A summary of the plan as at December 31, 2005 is as follows:

Exercise Price at Grant Date ($)	Adjusted Exercise Price ($)	Number of Rights Outstanding	Remaining Contractual Life of Rights (years)	Number of Rights Exercisable
12.25	9.00	32	1.4	33
12.49	12.23	118	2.5	118
12.18	10.19	1,172	3.4	399
15.42	14.21	27	4.2	9
12.27	10.22	1,349	3.3	559

The Trust recorded compensation expense of $6.5 million for the year ($5.2 million in 2004) for the cost associated with the rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 355,499 rights have been cancelled and 1,458,929 rights have been exercised to December 31, 2005.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2004:

	2004
Expected annual right's exercise price reduction	0.72
Expected volatility	13.2%
Risk-free interest rate	3.7%
Expected life of option (years)	1.1
Expected forfeitures	0%

Prior to 2004, the Trust recorded compensation expense on its Rights Plan using the intrinsic method. In 2004, the Trust adopted the fair value method. Use of the fair value prior to 2004 would have resulted in an immaterial impact to the Trust.

The following table reconciles the movement in the contributed surplus balance:

	2005	2004
Balance, beginning of year	**$ 6,475**	$ 3,471
Compensation expense	**6,524**	5,171
Net benefit on rights exercised (1)	**(6,617)**	(2,167)
Balance, end of year	**$ 6,382**	$ 6,475

(1) Upon exercise, the net benefit is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

Compensation expense has not been recorded for rights granted prior to 2003. The following table represents the pro forma net income and the pro forma net income per unit had the Trust applied the fair value method to rights granted in 2002.

Pro Forma Results	**2005**	2004
Net income as reported	**$ 356,935**	$ 241,690
Less: compensation expense for rights issued in 2002	**6,599**	3,189
Pro forma net income	**$ 350,336**	$ 238,501
Basic net income per trust unit		
As reported	**$ 1.90**	$ 1.32
Pro forma	**$ 1.86**	$ 1.30
Diluted net income per trust unit		
As reported	**$ 1.88**	$ 1.31
Pro forma	**$ 1.85**	$ 1.29

15. WHOLE TRUST UNIT INCENTIVE PLAN

In March 2004, the Board of Directors, upon recommendation of the Human Resources and Compensation Committee, approved a new Whole Trust Unit Incentive Plan (the "Whole Unit Plan") to replace the existing Trust Unit Incentive Rights Plan for new awards granted subsequent to March 31, 2004. The new Whole Unit Plan will result in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying notional units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of trust units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of trust units is variable and will vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the future performance of the Trust compared to its peers based on a performance multiplier. The performance multiplier is based on the percentile rank of the Trust's total unitholder return. The cash compensation issued upon vesting of the PTUs may range from zero to two times the number of the PTUs originally granted.

The fair value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period. As the value of the RTUs and PTUs is dependent upon the unit price, the expense recorded in the statement of income may fluctuate over time.

The Trust recorded compensation expense of $8.8 million and $1.9 million to general and administrative and operating expenses, respectively in 2005 ($2.9 million and $nil in 2004) for the estimated cost of the plan. The compensation expense was based on the December 31, 2005 unit price of $26.49 ($17.90 in 2004), distributions of $0.20 per unit per month during the year ($0.15 per month in 2004), and the number of units to be issued on maturity.

	2005		2004	
	Number of RTUs	**Number of PTUs**	Number of RTUs	Number of PTUs
Balance, beginning of year	**224,398**	**128,331**	–	–
Vested	**(78,745)**	**–**		
Granted	**367,030**	**304,655**	226,837	128,908
Forfeited	**(33,918)**	**(42,429)**	(2,439)	(577)
Balance, end of year	**478,765**	**390,557**	224,398	128,331

The following table reconciles the change in total accrued compensation liability relating to the Whole Unit Plan:

	December 31, 2005	December 31, 2004
Balance, beginning of year	**$ 2,915**	$ –
Increase in liabilities in the year (net of cash payments)		
General and administrative expense	**8,774**	2,915
Operating expense	**1,916**	–
Property, plant and equipment	**1,352**	–
Balance, end of year	**$ 14,957**	$ 2,915
Current portion of liability	**3,597**	1,022
Long-term liability	**$ 11,360**	$ 1,893

During the year $1.6 million in cash payments were made to employees relating to the Whole Unit Plan (2004 – $nil).

16. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Net income per unit has been determined based on the following:

	2005	2004
Weighted average trust units (1)	**188,237**	183,123
Trust units issuable on conversion of exchangeable shares (2)	**2,935**	2,982
Dilutive impact of rights (3)	**1,372**	1,756
Dilutive trust units and exchangeable shares	**192,544**	187,861

(1) Weighted average units excludes units issuable for exchangeable shares.
(2) Diluted units include units issuable for outstanding exchangeable shares at the period end exchange ratio.
(3) All outstanding rights were dilutive and therefore none have been excluded in the diluted unit calculation.

Basic net income per unit has been calculated based on net income after non-controlling interest divided by weighted average units. Diluted net income per unit has been calculated based on net income before non-controlling interest divided by dilutive units.

17. GAIN (LOSS) ON FOREIGN EXCHANGE

The following is a summary of the gain (loss) on commodity and foreign currency contracts for 2005:

	2005	2004
Unrealized (loss) gain on US$ denominated debt	**$ (4,221)**	$ 21,922
Realized gain (loss) on US$ denominated debt repayments	**10,580**	(3,495)
Total non-cash gain on US$ denominated transactions	**$ 6,359**	$ 18,427
Realized cash gain on US$ denominated transactions	**53**	2,286
Total foreign exchange gain	**$ 6,412**	$ 20,713

18. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2005:

	Payments Due By Period				
($ millions)	2006	2007-2008	2009-2010	Thereafter	Total
Debt repayments (1)	–	279.4	49.2	198.0	526.6
Reclamation fund contributions (2)	6.1	11.8	10.2	80.9	109.0
Purchase commitments	2.4	3.4	3.2	8.0	17.0
Operating leases	4.1	8.1	7.3	–	19.5
Derivative contract premiums (3)	12.4	–	–	–	12.4
Retention bonuses	1.0	1.0	–	–	2.0
Total contractual obligations	26.0	303.7	69.9	286.9	686.5

(1) Includes long-term and short-term debt.
(2) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition.
(3) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures by means of giving the necessary authorizations to incur capital in a future period. This commitment has not been disclosed in the above commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

Other items excluded from the commitment table above include commitments regarding asset retirement obligations and the Whole Unit Plan. These amounts have been accrued for, however, the final payment amounts are uncertain and are therefore excluded above.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. The Trust has an obligation for future fixed transportation charges, pursuant to one aggregator contract, for which the transportation is not physically being utilized due to a shortage of demand. The Trust has estimated that its total future liability for the future transportation charges approximates $10 million over the period 2006 through 2012. This transportation charge will be realized as a reduction of the Trust's net gas price over the corresponding period as the charges are incurred. For all other aggregator contracts, prices received by the Trust closely track to market prices.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results of operations.

In addition to the above, the Trust has commitments related to its risk management program (see Note 9).

19. SUBSEQUENT EVENTS

FINANCIAL WTI CRUDE OIL CONTRACTS

On January 12, 2006, the Trust entered into a series of $55 – $90 ($40) 3-way collars for the period February 2006 to December 2009 for 5,000 bbl per day. The contracts will result in a $7.5 million premium payment during the duration of the contracts.

PROPERTY ACQUISITIONS

During January 2006, the Trust acquired property, plant, and equipment for consideration of $26 million.

20. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in some respects from US GAAP. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements are immaterial except as described below:

The application of US GAAP would have the following effect on net income as reported.

	2005	2004
Net income as reported for Canadian GAAP	**$ 356,935**	$ 241,690
Adjustments:		
Depletion and depreciation (a)	**15,639**	19,004
Unrealized gain on derivative instruments (c)	**–**	13,721
Unit based compensation (b)	**(7,274)**	(9,219)
Non-controlling interest (e)	**5,545**	3,951
Effect of applicable income taxes on the above adjustments	**(5,357)**	(2,142)
Net income under US GAAP	**$ 365,488**	$ 267,005
Net income per trust unit (Note 16)		
Basic (f)	**$ 1.91**	$ 1.43
Diluted (f)	**$ 1.90**	$ 1.42
Comprehensive income:		
Net income under US GAAP	**$ 365,488**	$ 267,005
Unrealized gain (loss) on derivative instruments, net of applicable income taxes	**1,593**	(2,441)
Comprehensive income (c)	**$ 367,081**	$ 264,564

The application of US GAAP would have the following effect on the consolidated balance sheets as reported:

	2005		2004	
	Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
Property, plant and equipment	**$ 2,929,977**	**$ 2,797,398**	$ 2,016,646	$ 1,868,428
Commodity and foreign currency contracts	**(4,042)**	**(5,261)**	(4,042)	(7,685)
Future income taxes	**(515,877)**	**(491,831)**	(300,406)	(270,173)
Non-controlling interest (e)	**(37,494)**	**–**	(35,967)	–
Temporary equity (d)	**–**	**(5,077,983)**	–	(3,379,594)
Unitholders' capital	**(2,230,842)**	**–**	(1,926,351)	–
Contributed surplus	**(6,382)**	**–**	(6,475)	–
Accumulated earnings	**(1,235,742)**	**1,676,473**	(878,807)	651,227
Accumulated other comprehensive loss	**–**	**802**	–	2,395

The above noted differences between Canadian GAAP and US GAAP are the result of the following:

(a) The Trust performs an impairment test that limits net capitalized costs to the discounted estimated future net revenue from proved and risked probable oil and natural gas reserves plus the cost of unproved properties less impairment, using forward prices. For Canadian GAAP the discount rate used must be equal to a risk free interest rate. Under US GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount rate of 10 per cent. Prices used in the US GAAP ceiling tests are those in effect at year end. The amounts recorded for depletion and depreciation have been adjusted in the periods following the additional write-downs taken under US GAAP to reflect the impact of the reduction of depletable costs.

(b) For US GAAP purposes, the Rights Plan has been accounted for as a variable compensation plan as the exercise price of the rights is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price over the adjusted exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. After the rights have vested, compensation expense is recognized in income in the period in which a change in the market price of the units or the exercise price of the rights occurs. Canadian GAAP requires that all unit-based compensation plans be fair valued. As such, an adjustment to earnings has been recorded to reflect the additional compensation expense on rights issued prior to January 1, 2003 for US GAAP purposes and for the difference between the intrinsic value and the fair value of rights issued since that time which are still outstanding at December 31, 2005.

(c) US GAAP requires that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded on the consolidated balance sheet as either an asset or liability measured at fair value and requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs, and requires that a company formally document, designate, and assess the effectiveness of derivative instruments that receive hedge accounting treatment. Under Canadian GAAP, derivative instruments that meet these specific hedge accounting criteria are not recorded on the consolidated balance sheet. In addition, unrealized gains and losses on effective hedges are not recorded in the financial statements. The Trust formally documented and designated all hedging relationships and verified that its hedging instruments were effective in offsetting changes in actual prices and rates received by the Trust. Hedge effectiveness is monitored and any ineffectiveness is reported in the consolidated statement of income.

A reconciliation of the components of accumulated other comprehensive income related to all derivative positions is as follows:

	2005		2004	
	Gross	**After Tax**	Gross	After Tax
Accumulated other comprehensive (loss) income, beginning of year	**$ (3,643)**	**$ (2,395)**	$ 78	$ 46
Effect of change in corporate tax rate	**–**	**–**	–	(5)
Reclassification of net realized gains into earnings	**(799)**	**(529)**	(969)	(637)
Net change in fair value of derivative instruments	**3,223**	**2,122**	(2,752)	(1,799)
Accumulated other comprehensive loss, end of year	**$ (1,219)**	**$ (802)**	$ (3,643)	$ (2,395)

(d) Under US GAAP, as the units are redeemable at the option of the unitholder, the units must be valued at their redemption amount and presented as temporary equity in the consolidated balance sheet. The redemption value of the units is determined with respect to the trading value of the units and the unit equivalent of the exchangeable shares at each balance sheet date. Under Canadian GAAP, all units are classified as permanent equity. As at December 31, 2005 and 2004, the Trust has classified \$5.1 billion and \$3.4 billion, respectively, as temporary equity in accordance with US GAAP. Changes in redemption value between periods are charged or credited to accumulated earnings.

(e) Under Canadian GAAP, ARL Exchangeable Shares are classified as non-controlling interest to reflect a minority ownership in one of the Trust's subsidiaries. As these exchangeable shares must ultimately be converted into units, the exchangeable shares are classified as temporary equity along with the units for US GAAP purposes.

(f) Under Canadian GAAP, basic net income per unit is calculated based on net income after non-controlling interest divided by weighted average units and diluted net income per unit is calculated based on net income before non-controlling interest divided by dilutive units. Under US GAAP, as the exchangeable shares are classified in the same manner as the units with no non-controlling interest treatment, basic net income per unit is calculated based on net income divided by weighted average units and the unit equivalent of the outstanding exchangeable shares. Concurrently, diluted net income per unit is calculated based on net income divided by a sum of the weighted average units, the unit equivalent of the outstanding exchangeable shares, and the dilutive impact of rights.

(g) In 2005 and 2004, the FASB and the CICA issued new and revised standards, all of which were assessed by management to be not applicable to the Trust with the exception of the following:

- In December 2004, the FASB Issued SFAS No. 123R, "Share Based Payments", which addresses the issue of measuring compensation cost associated with Share Based Payment plans. This statement requires that all such plans, for public entities, be measured at fair value using an option pricing model whereas previously certain plans could be measured using either a fair value method or an intrinsic value method. The revision is intended to increase the consistency and comparability of financial results by only allowing one method of application. This revised standard is effective fiscal year 2006. The Trust will adopt SFAS 123R on January 1, 2006 and will determine the impact in 2006.

- In 2004, FASB issued FAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion No. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges of non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges which occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Earlier

application is permitted for non-monetary asset exchanges which occur in fiscal periods beginning after the issue date of this statement. Currently, this statement does not have an impact on the Trust; however, this may result in a future impact to the Trust if it enters into any non-monetary asset exchanges.

- In May 2005, FASB issued FAS 154, "Accounting Changes in Error Corrections", changes the requirements for the accounting for and reporting of a change in accounting principle. The standard is effective for the Trust in fiscal 2006
- In January 2005, the CICA approved Handbook Section 1530, "Comprehensive Income". The new standard is intended to harmonize Canadian GAAP with US GAAP. The new standard is effective for the Trust in the first quarter of 2007.

OFFICERS AND SENIOR MANAGEMENT

JOHN P. DIELWART, B.SC., P.ENG.

Mr. Dielwart is President and Chief Executive Officer of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a Past-Chairman of the board of governors for the Canadian Association of Petroleum Producers ("CAPP"). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has been a director of ARC since 1996.

STEVEN W. SINCLAIR, B. COMM., CA

Mr. Sinclair is Senior Vice-President Finance and Chief Financial Officer of ARC Resources Ltd. and oversees all of the financial and marketing affairs of ARC Energy Trust. Mr. Sinclair has a Bachelor of Commerce from the University of Calgary, obtained his Chartered Accountant's designation in 1981 and has over 20 years experience within the finance, accounting and taxation areas of the oil and gas industry. Mr. Sinclair has been with ARC since 1996.

MYRON M. STADNYK, P.ENG.

Mr. Stadnyk is Senior Vice-President and Chief Operating Officer of ARC Resources Ltd. and is responsible for all of ARC's operational and land activities as well as engineering, geology and geophysics related activities. He has over 20 years experience in all aspects of oil and gas production operations. Prior to joining ARC in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations and oil and gas facility design and construction. He has a B.Sc. in Mechanical Engineering and is a member of the Association of Professional Engineers in Alberta, Saskatchewan and British Columbia.

DOUG J. BONNER, P.ENG.

Mr. Bonner is Senior Vice-President, Corporate Development of ARC Resources Ltd. and is responsible for the strategic development and expansion of ARC's assets. He holds a B.Sc. in Geological Engineering from the University of Manitoba. Mr. Bonner's major area of expertise is reservoir engineering and he has extensive technical knowledge of oil and natural gas fields throughout western Canada, the east coast and northern Canada. Prior to joining ARC in 1996, Mr. Bonner spent 18 years with various major oil and natural gas companies in positions of increasing responsibility.

DAVID P. CAREY, P.ENG.

Mr. Carey is Senior Vice-President, Capital Markets of ARC Resources Ltd. and is responsible for all facets of investor relations and corporate governance. He holds both a B.Sc. in Geological Engineering and a MBA from Queen's University. Mr. Carey has over 20 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations in western Canada, oilsands, the Canadian frontiers and internationally. Prior to joining ARC in 2001, Mr. Carey held senior positions with Athabasca Oil Sands Investments Inc. and Gulf Canada Resources.

SUSAN D. HEALY, P. LAND

Ms. Healy is Senior Vice-President, Corporate Services of ARC Resources Ltd. and oversees all human resources, information technology and office services related activities. Ms. Healy joined the Trust at inception in July 1996, bringing with her at that time, over 17 years of diverse experience gained from working with junior and senior oil and gas companies.

TERRY M. ANDERSON, P.ENG.

Mr. Anderson is Vice-President, Operations of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has a B.Sc. in Petroleum Engineering and is a member of the Association of Professional Engineers in Alberta, Saskatchewan and British Columbia. Mr. Anderson has 12 years of experience in drilling, completion, pipeline, facility and production operations. Prior to joining ARC in 2000, he worked at a major oil and gas company.

YVAN CHRETIEN, B.COMM.

Mr. Chretien is Vice-President, Land of ARC Resources Ltd. and is responsible for all of ARC's land related activities. He has 15 years of land related experience. Prior to joining ARC in 2001, Mr Chretien worked for both senior and intermediate oil and gas companies.

P. VAN R. DAFOE, B. COMM., CMA

Mr. Dafoe is Treasurer of ARC Resources Ltd. and is responsible for all of ARC's Treasury related activities. He has a Bachelor of Commerce – Honours from the University of Manitoba and obtained his Certified Management Accountant's designation in 1995. Mr. Dafoe joined ARC in 1999 after 13 years with various companies in the finance and accounting area of the oil and gas industry.

ALLAN R. TWA, Q.C.

Mr. Twa acts as Corporate Secretary of ARC Resources Ltd. A member of the Alberta Bar since 1971, Mr. Twa is a partner in the law firm Burnet, Duckworth & Palmer LLP. Mr. Twa holds a B.A. (Political Science) from the University of Calgary, a LL.B. from the University of Alberta and a LL.M. from the University of London, England. Over the last 30 years, Mr. Twa has been engaged in a legal practice involving legal administration of public companies and trusts, corporate finance, and mergers and acquisitions.

BOARD OF DIRECTORS

FRED C. COLES, B.SC., P.ENG.

Mr. Coles is founder and President of Menehune Resources Ltd., having previously served as the Executive Chairman of Applied Terravision Systems Inc. to March 15, 2002. In his earlier career Mr. Coles worked as a reservoir engineer for a number of oil and gas companies, prior to undertaking the role of Chairman and President of an engineering consulting firm specializing in oil and gas. Mr. Coles also sits as a Director on the boards of the following oil and gas companies: Cyries Energy Inc., Deep Resources Ltd., Progress Energy Trust, Crew Energy Inc., Masters Energy Inc., High Point Resources Inc. and Mission Oil and Gas Inc. He is a member of the Association for Professional Engineers, Geologists and Geophysicists of Alberta and the Canadian Institute of Mining, Metallurgy and Petroleum. Mr. Coles has been a Director of ARC since 1996.

WALTER DEBONI, P.ENG., MBA

Mr. DeBoni recently retired from Husky Energy Inc. where he held the position of VP, Canada Frontier & International Business. Prior to this Mr. DeBoni was CEO of Bow Valley Energy for a number of years. In addition to his time at Husky and Bow Valley he has also held numerous top executive posts in the oil and gas industry with major corporations. Mr. DeBoni holds a B.A.Sc. Chem. Eng. from the University of British Columbia, a MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers. He is a past Chairman of the Petroleum Society of CIM, a past Director of the Society of Petroleum Engineers and has been a Director of ARC since 1996.

JOHN P. DIELWART, B.SC., P.ENG.

Mr. Dielwart is President and CEO of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is a Past-Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

FRED DYMENT

Mr. Dyment has 29 years experience in the oil and gas business and is currently an independent businessman. His past business career included positions as President and CEO for Maxx Petroleum and President and CEO of Ranger Oil Limited. Mr. Dyment received a Chartered Accountant designation from the province of Ontario in 1972. Mr. Dyment currently sits as a Director on the Boards of Tesco Corporation, Transglobe Energy Corporation and ZCL Composites Inc. He has been a Director of ARC since 2003.

MICHAEL M. KANOVSKY, B.SC., P.ENG., MBA

Mr. Kanovsky graduated from Queen's University and the Ivey School of Business. Mr. Kanovsky's business career included the position of VP of Corporate Finance with a major Canadian investment dealer followed by co-founding Northstar Energy Corporation and PowerLink Corporation (electrical cogeneration) where he served as Senior Executive Board Chariman and Director. Mr. Kanovsky is a Director of Bonavista Petroleum Inc., Devon Energy Corporation, Transalta Corporation and Pure Technologies Inc. He has been a Director of ARC since 1996.

HERB PINDER, B.ARTS, LL.B., MBA

Mr. Pinder has gained extensive experience as a director on various public company boards over the last twenty years. As a result he brings an extensive business background to ARC covering several industries and a broad knowledge of corporate governance. Currently, Mr. Pinder is the President of the Goal Group, a private equity management firm located in Saskatoon, Saskatchewan. He is a director of the Saskatchewan Wheat Pool and C1 Energy Ltd., as well as several private companies. Mr. Pinder also serves as a director of the C.D. Howe Institute and as a Trustee of the Fraser Institute. Mr Pinder became a director of ARC beginning in 2006.

JOHN M. STEWART, B.SC., MBA

Mr. Stewart is a founder and Vice-Chairman of ARC Financial Corporation where he holds senior executive responsibilities focused primarily within the area of private equity investment management. He holds a B.Sc. in Engineering from the University of Calgary and a MBA from the University of British Columbia. Prior to ARC Financial, he was a Director and Vice-President of a major national investment firm. His career and experience span nearly 30 years with a focus on oil and gas and finance. He is a director for ProEx Energy Ltd. Mr. Stewart has been a Director of ARC since 1996.

MAC H. VAN WIELINGEN

Mr. Van Wielingen has served as Vice-Chairman and Director of ARC Resources Ltd. since its formation in 1996. He is Co-Chairman and a founder of ARC Financial Corporation. Previously Mr. Van Wielingen was a Senior Vice-President and Director of a major national investment dealer responsible for all corporate finance activities in Alberta. He has managed numerous significant corporate merger and acquisition transactions, capital raising projects and equity investments relating to the energy sector. He is a director of Western Oil Sands Inc. Mr. Van Wielingen holds an Honours Business Degree from the University of Western Ontario Business School and has studied post-graduate Economics at Harvard University.

CORPORATE INFORMATION

DIRECTORS

MAC H. VAN WIELINGEN (1) (3) (4)
Chairman

WALTER DEBONI (1) (4) (5)
Vice-Chairman

JOHN P. DIELWART
President and Chief Executive Officer

FREDERIC C. COLES (2) (3) (5)

FRED J. DYMENT (1) (2)

MICHAEL M. KANOVSKY (1) (2)

HERB PINDER (3) (4)

JOHN M. STEWART (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserve Audit Committee
(3) Member of Human Resources and Compensation Committee
(4) Member of Policy and Board Governance Committee
(5) Health, Safety and Environment Committee

OFFICERS

JOHN P. DIELWART
President and Chief Executive Officer

DOUG J. BONNER
Senior Vice-President, Corporate Development

DAVID P. CAREY
Senior Vice-President, Capital Markets

SUSAN D. HEALY
Senior Vice-President, Corporate Services

STEVEN W. SINCLAIR
Senior Vice-President Finance and Chief Financial Officer

MYRON M. STADNYK
Senior Vice-President and Chief Operating Officer

TERRY ANDERSON
Vice-President, Operations

YVAN CHRETIEN
Vice-President, Land

P. VAN R. DAFOE
Treasurer

ALLAN R. TWA
Corporate Secretary

EXECUTIVE OFFICE

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AUDITORS

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CALGARY, ALBERTA

ENGINEERING CONSULTANTS

GLJ PETROLEUM CONSULTANTS LTD.
CALGARY, ALBERTA

LEGAL COUNSEL

BURNET DUCKWORTH & PALMER LLP
CALGARY, ALBERTA

STOCK EXCHANGE LISTING

THE TORONTO STOCK EXCHANGE
TRADING SYMBOLS:

AET.UN (Trust Units)
ARX (Exchangeable Shares)

INVESTOR INFORMATION

VISIT OUR WEBSITE AT
www.arcenergytrust.com

OR CONTACT:
Investor Relations
(403) 503-8600 or
1-888-272-4900 (Toll Free)

PRIVACY OFFICER

SUSAN D. HEALY
privacy@arcresources.com
Facsimile: (403) 509-7260

UNITHOLDER INFORMATION

NOTICE OF ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting will be held on May 15, 2006 at 3:30 p.m. in the Imperial Ballroom at the Hyatt Regency Hotel, 700 Centre Street SE, Calgary, Alberta.

DISTRIBUTION REINVESTMENT AND OPTIONAL CASH PAYMENT PROGRAM

ARC Energy Trust unitholders should be aware of the Distribution Reinvestment Plan ("DRIP") under which a Canadian resident registered unitholder can elect to reinvest cash distributions into new ARC Energy Trust units. If distributions are reinvested, a unitholder can elect to make optional cash payments under the DRIP between a minimum of $500 to a maximum of $3,000 per distribution date to purchase additional trust units. All units purchased under the DRIP are made at 95 per cent of the prevailing market prices without any additional fees or commissions. For further details on the DRIP please refer to our website, www.arcenergytrust.com or contact Computershare Trust Company of Canada.

CORPORATE CALENDAR

2006

May 10	2006 Q1 Results
May 15	Annual and Special Meeting

GLOSSARY OF ABBREVIATIONS

API	American Petroleum Institute
bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe*	barrels of oil equivalent
boe/d*	barrels of oil equivalent per day
Capex	capital expenditures
FD&A	costs finding, development and acquisition costs
F&D	finding and development costs
FDC	future development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
mbbl	thousand barrels
mboe*	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
mmboe*	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
RLI	reserve life index
WTI	West Texas Intermediate

* Boes may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

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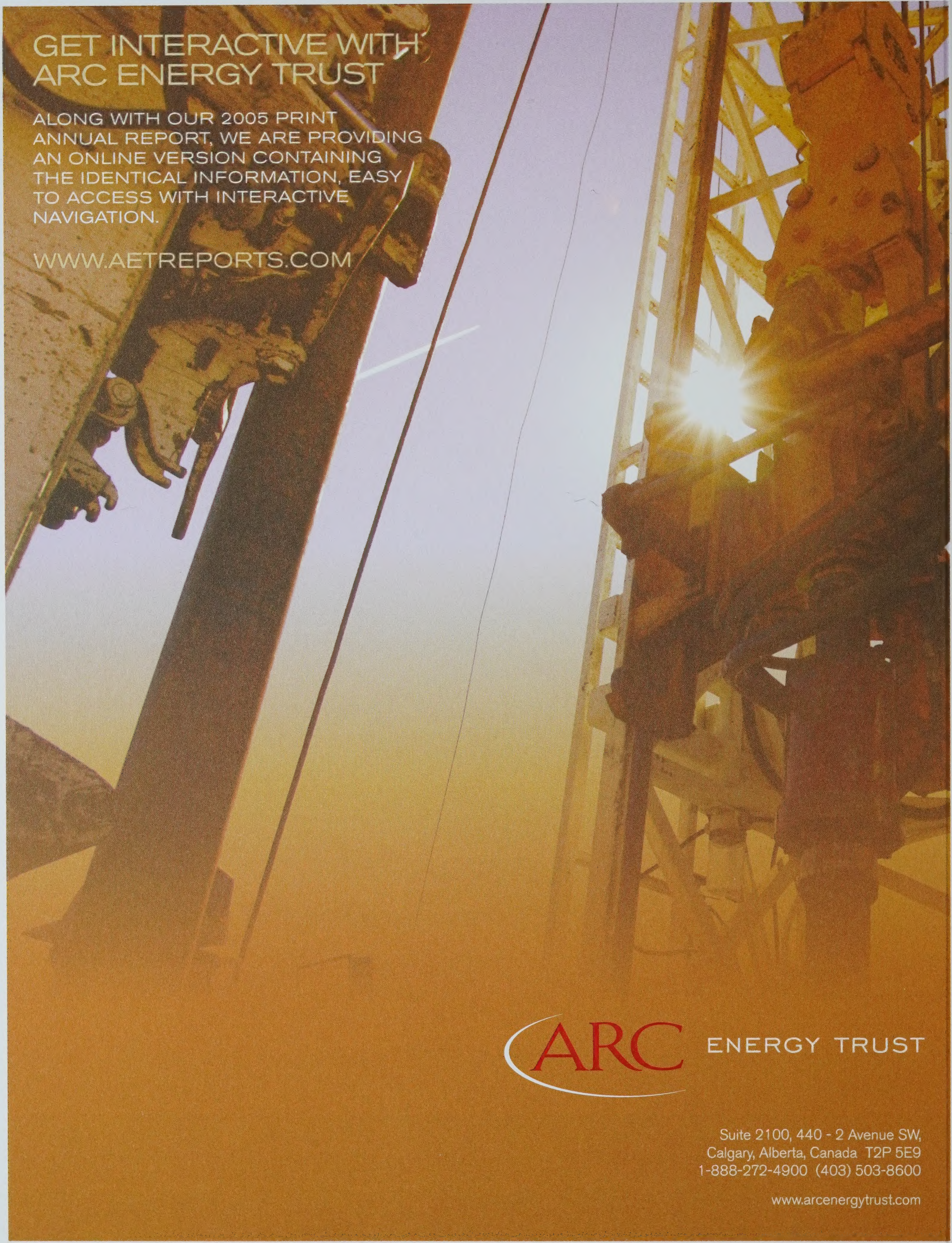
Canada's Climate Change Voluntary Challenge and Registry. The industry's voluntary effort to reduce greenhouse gas emissions and document the efforts year over year.

Canadian Association of Petroleum Producers Stewardship

Members commit to continuous improvement in the responsible management, development and use of our natural resources; protection of our environment; and, the health and safety of our workers and the general public



GET INTERACTIVE WITH ARC ENERGY TRUST

ALONG WITH OUR 2005 PRINT ANNUAL REPORT, WE ARE PROVIDING AN ONLINE VERSION CONTAINING THE IDENTICAL INFORMATION, EASY TO ACCESS WITH INTERACTIVE NAVIGATION.

WWW.AETREPORTS.COM

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